To: Wilcox, Jahan[wilcox.jahan@epa.gov]
Cc: Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]; Jackson, Ryan[jackson.ryan@epa.gov]
From: Bowman, Liz
Sent: Thur 12/7/2017 5:43:38 PM
Subject: FW: Signed NSR Memo
NSR Policy Memo.12.7.17.pdf
ATT00001.htm

Can you please help us get this to a few people who might be interested, after the Hearing concludes? I plan to send it to Mary Kissel on the WSJ editorial page, please send it to the reporters you suggest. The program has indicated they are going to give it to Politico, E&E, etc. as soon as they get a copy, so if you want to provide it some folks after the hearing, that would be appreciated. Background on the issue is below:

Draft Desk Statement

Dec. 7 DTE/NSR Memo

Ex. 5 - Deliberative Process

The primary purpose of the memo is to clarify that so long as a company complies with the procedural requirements of a preconstruction analysis, then EPA will not second-guess that analysis.

Providing certainty and clarity on this issue is an important first step to encouraging investments across all industrial sectors to move forward with incorporating new technologies and improving operational efficiencies yielding both economic and environmental benefits.

The memo is not a final agency action and does not change or substitute for any law or regulation. Nor is it legally enforceable.

Depending upon individual facts and circumstances, it may not apply to a particular situation. More information: https://www.epa.gov/nsr

To: Dominguez, Alexander[dominguez.alexander@epa.gov]
Cc: Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]
From: Leslie Sue Ritts
Sent: Thur 11/2/2017 3:36:37 PM
Subject: NEDA/CAP NSR Issue Paper: "Begin Actual Construction"
Begin Actual Construction.pdf

Dear Alex,

Amy Dewey will drop off the notebook with you that has a hard copy of this and all (and there are a lot of them) references for you, Mandy and Justin. Let me know if you have questions and when it is possible to discuss it.

My best,

Leslie Sue Ritts

Ritts Law Group, PLLC

620 Fort Williams Parkway

Alexandria, VA 22304

(703) 823-2292 (office)

(703) 966-3862 (cell)

lritts@rittslawgroup.com

Please note new email address

have received this transmission in error, immediately notify us at the above telephone number.

To: Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]
Cc: Dominguez, Alexander[dominguez.alexander@epa.gov]; Dunham, Sarah[Dunham.Sarah@epa.gov]
From: Lewis, Josh
Sent: Thur 10/5/2017 4:42:01 PM
Subject: Fwd: NSR Policy Memo
OGC NSR DTE issue options analysis 10-4 am draft.docx
ATT00001.htm
NSR policy memo_draft_10-4-17PSLrev.docx
ATT00002.htm

Ahead of our weekly meeting tomorrow at 9, wanted to send the latest draft NSR policy memo. The other attachment is a document prepared by OGC which is an analysis of options for addressing NSR issues raised by DTE (you'll see one of the options is the policy memo)

Concerning the policy memo, we initially drafted a brief document just laying out EPA's

Ex. 5 - Deliberative Process/Attorney-Client

OGC staff attorneys have reviewed this draft. The draft will go shortly to Justin, Lorie, and Gautam for review. Thus far OECA and the Regional Offices have not been engaged.

We can talk more tomorrow about this, including next steps.

To: Gunasekara, Mandy[Gunasekara.Mandy@epa.gov]
Cc: Dunham, Sarah[Dunham.Sarah@epa.gov]
From: Lewis, Josh
Sent: Tue 6/20/2017 1:23:52 PM
Subject: Follow up re: NSR and permitting
Permit Streamlining.draft for Mandy.docx

Last Friday you asked for draft permit streamlining/NSR materials. In the attached word doc you'll find two tables: Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

As we discussed, this is a work in progress and still needs further review/discussion with OGC and OECA.

Josh

To: Lewis, Josh[Lewis.Josh@epa.gov]; Sarah Dunham (Dunham.Sarah@epa.gov)[Dunham.Sarah@epa.gov]
From: Gunasekara, Mandy
Sent: Tue 9/12/2017 5:57:16 PM
Subject: NSR Memo
Emissions Projection Rule_Outline_DRAFT.docx

Following up from Friday, attached are a few points regarding the NSR memo I mentioned. This should get things started.

Mandy M. Gunasekara

Senior Policy Advisor for Office of Air and Radiation

Office of the Administrator

US Environmental Protection Agency

To: Dominguez, Alexander[dominguez.alexander@epa.gov]
From: Gunasekara, Mandy
Sent: Thur 9/7/2017 3:55:19 PM
Subject: NSR

Can you add that to the list for my meeting with Sarah – NSR memo

Mandy M. Gunasekara

Senior Policy Advisor for Office of Air and Radiation

Office of the Administrator

US Environmental Protection Agency

From: Gunasekara, Mandy
Location: 3204WJC-South
Importance: Normal
Subject: Accepted: NSR Memo, conference line, 1 Ex. 6 - Personal Privacy code (Ex. 6 - Personal Privacy
Start Date/Time: Mon 12/11/2017 9:30:00 PM
End Date/Time: Mon 12/11/2017 10:00:00 PM

To: Catanzaro, Michael J. EOP/WHO[Ex. 6 - Personal Privacy]; Moran, John S. EOP/WHO[Ex. 6 - Personal Privacy]; Szabo, Aaron L. EOP/CEQ[ ]
From: Gunasekara, Mandy
Sent: Wed 12/6/2017 6:20:45 PM
Subject: Memo on NSR Reform
NSR policy memo_draft final_2017 12 05.docx

Following up from our conversation, attached is the almost final version of the DTE/NSR reform memo. I'll give you a heads up when we finalize the timing (my goal is early tomorrow).

Mandy M. Gunasekara

Principal Deputy Assistant Administrator

Office of Air and Radiation

US Environmental Protection Agency

To: Traylor, Patrick[traylor.patrick@epa.gov]
Cc: Bodine, Susan[bodine.susan@epa.gov]
From: Gunasekara, Mandy
Sent: Wed 10/25/2017 6:03:32 PM
Subject: RE: NSR Reform
NSR policy memo_draft_10-4-17PSLrev.docx

Yes – see attached. The team sent this to me a couple weeks ago. I have not yet spent significant time on it. Please take a look and let me know your thoughts. Once we get a further down the process, let's plan to meet and discuss.

Best,

Mandy

From: Traylor, Patrick
Sent: Wednesday, October 25, 2017 10:24 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Bodine, Susan <bodine.susan@epa.gov>
Subject: NSR Reform

Mandy:

Would you please include Susan and me at the very earliest opportunity in the distribution for whatever draft memoranda or guidance documents that Ex. 5 - Deliberative Process Ex. 5 - Deliberative Process? We have your one-page outline.

Thanks,

Patrick

Patrick Traylor

Deputy Assistant Administrator

Office of Enforcement and Compliance Assurance

U.S. Environmental Protection Agency

(202) 564-5238 (office)

(202) 809-8796 (cell)

From: Gunasekara, Mandy
Location: WJCS-3216
Importance: Normal
Subject: Fwd: NSR Memorandum Discussion
Start Date/Time: Mon 12/4/2017 6:00:00 PM
End Date/Time: Mon 12/4/2017 7:00:00 PM

Can you respond that I won't be available until 115 as I'll be briefing hr admin on air issues for hearing until then

Sent from my iPhone

Begin forwarded message:

> **From:** "Traylor, Patrick" <traylor.patrick@epa.gov>
> **To:** "Bodine, Susan" <bodine.susan@epa.gov>, "Schwab, Justin" <Schwab.Justin@epa.gov>, "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
> **Subject: NSR Memorandum Discussion**

To: Lewis, Josh[Lewis.Josh@epa.gov]
From: Gunasekara, Mandy
Sent: Mon 12/4/2017 3:19:06 PM
Subject: Fwd: NSR Memo
NSR policy memo_draft_2017 12 2 edits.docx
ATT00001.htm

FYI

Sent from my iPhone

Begin forwarded message:

From: "Gunasekara, Mandy" <Gunasekara.Mandy@epa.gov>
Date: December 4, 2017 at 9:02:53 AM EST
To: "Bodine, Susan" <bodine.susan@epa.gov>, "Patrick Traylor (traylor.patrick@epa.gov)" <traylor.patrick@epa.gov>
Cc: "Jackson, Ryan" <jackson.ryan@epa.gov>, "Dravis, Samantha" <dravis.samantha@epa.gov>, "Schwab, Justin" <schwab.justin@epa.gov>
Subject: NSR Memo

Good Morning –

Attached is the latest version of the NSR Memo pertaining to the issues at issue in the DTE case. I thought we may have more time, but know now that the cert hearing is planned for Wednesday. This memo needs to go out before. I'd like to send it with the Administrator this evening for him to review and then follow-up tomorrow with a meeting/discussion if necessary. I gave Hayley a heads up and she said we can work in time. Please run the traps on this from your end. I apologize for the short notice, but will move items around and make myself available to discuss this afternoon if necessary.

Thanks,

Mandy

Mandy M. Gunasekara

Principal Deputy Assistant Administrator

Office of Air and Radiation

US Environmental Protection Agency

To: Millett, John[Millett.John@epa.gov]
Cc: Dominguez, Alexander[dominguez.alexander@epa.gov]
From: Gunasekara, Mandy
Sent: Fri 12/8/2017 7:00:10 PM
Subject: RE: Abby Smith on Twitter: ".@EPAScottPruitt sent a memo to region heads clarifying how EPA will apply new source review while it reviews the program. @jenpenned breaks down what it means, with more to come: https://t.co/Wgt3UHMdB1"

Thanks, John.
I also saw the E&E article - think they mischaracterize what we are doing here, but to be expected.

-----Original Message-----
From: Millett, John
Sent: Friday, December 8, 2017 1:54 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Abby Smith on Twitter: ".@EPAScottPruitt sent a memo to region heads clarifying how EPA will apply new source review while it reviews the program. @jenpenned breaks down what it means, with more to come: https://t.co/Wgt3UHMdB1"

FYI —

https://mobile.twitter.com/AbbySmithDC/status/939194735608188928

Sent from my iPhone

To: Lewis, Josh[Lewis.Josh@epa.gov]
Cc: Koerber, Mike[Koerber.Mike@epa.gov]
From: Gunasekara, Mandy
Sent: Fri 12/8/2017 5:08:28 PM
Subject: RE: NSR

He is caught up in some other matters. That being said, go ahead and send it out to the Air Division Directors and whoever else in OAR needs it.
-----Original Message-----
From: Lewis, Josh
Sent: Friday, December 8, 2017 11:34 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
Cc: Koerber, Mike <Koerber.Mike@epa.gov>
Subject: RE: NSR

Do you know if Ryan is planning to send to the RAs today? OAQPS wants to send to the Air Division Directors, but didn't want to get ahead of anything Ryan was planning to do

Josh

-----Original Message-----
From: Gunasekara, Mandy
Sent: Thursday, December 07, 2017 6:27 PM
To: Lewis, Josh <Lewis.Josh@epa.gov>; Millett, John <Millett.John@epa.gov>; DeLuca, Isabel <DeLuca.Isabel@epa.gov>; White, Elizabeth <white.elizabeth@epa.gov>; Hope, Brian <Hope.Brian@epa.gov>
Subject: NSR

Thanks for your help today in getting the memo over the finish line!

Sent from my iPhone

To: Jackson, Ryan[jackson.ryan@epa.gov]
From: Gunasekara, Mandy
Sent: Thur 12/7/2017 10:57:21 PM
Subject: NSR Memo Email to RAs
NSR Policy Memo.12.7.17.pdf
ATT00001.txt

Memo is attached. There is a "Regional Administrators" list in outlook to send this to all 10. Please cc me (since Bill is recused), Susan, Minoli and Justin. I'd suggest simply stating:

Dear Regional Administrators:
Please see attached for a memo regarding New Source Review the Administrator signed today.
Best,
Ryan

To: Harlow, David[harlow.david@epa.gov]; Dominguez, Alexander[dominguez.alexander@epa.gov]
From: Gunasekara, Mandy
Sent: Mon 11/27/2017 2:15:43 PM
Subject: NSR Reform Memo
NSR policy memo_draft_10-4-17PSLrev.docx

First one attached.

Mandy M. Gunasekara

Principal Deputy Assistant Administrator

Office of Air and Radiation

US Environmental Protection Agency

To: Bodine, Susan[bodine.susan@epa.gov]
From: Gunasekara, Mandy
Sent: Fri 9/22/2017 5:54:06 PM
Subject: NSR Memo
Emissions Projection Rule_Outline_DRAFT.DOCX

Attached is what I sent to program folks last Tuesday.

Mandy M. Gunasekara

Senior Policy Advisor for Office of Air and Radiation

Office of the Administrator

US Environmental Protection Agency

To: Jackson, Ryan[jackson.ryan@epa.gov]
From: Gunasekara, Mandy
Sent: Tue 11/14/2017 2:19:31 PM
Subject: NSR

Suggested TPs:

Ex. 5 - Deliberative Process

Sent from my iPhone

From: Kordzi, Stephanie
Location: Call-in Number: 866-299-3188 II Code: Ex. 6 - Personal Privacy
Importance: Normal
Subject: NSR/Title V Staff Call - Wednesday, February 1, 2017
Start Date/Time: Wed 2/1/2017 7:00:00 PM
End Date/Time: Wed 2/1/2017 9:00:00 PM
Ameren_Decision Jan 2017.pdf
DTE II on Appeal-Sixth Circuit Opinion Jan 2017.pdf
Roxul Comment Letter.pdf
Roxul Modeling Review Summary Dec. 2017.docx
Roxul R4 APTMD Hot Issues for HQ-012717.docx
Status of NSRTitle V Rulemaking Actions_for Jan 25 2017 final.docx
2-1-17 Agenda for Monthly Air Permitting Staff Call.docx
PAL EU table_draft_8-18-16.docx

All,

We have a full Agenda for today's NSR/Title V call – I've included an additional attachment. Please let me know if you have any questions about the Agenda or associated attachments.

Stephanie Kordzi

Environmental Engineer

EPA Region 6 (6MM-AP)

214-665-7520

Agenda for Monthly Air Permitting Staff Call

February 1, 2017

2:00 – 4:00 pm Eastern Time

Call-in Number: 866-299-3188 || Code: Ex. 6 - Personal Privacy

Today's agenda:

2:00 pm Roll call and New Staff Introductions – Stephanie Kordzi (R6)

2:05 pm Regional Issues || Lori Shepherd (R4) (see attachment)

• Roxul USA Air Permit – Modeling Issues

• Upcoming Air Permitting Workshop for state, local, and tribal agencies

2:20 pm Rulemaking Updates – Charles Buckler (OAQPS) (see attachment)

2:30 pm Update || Recent Petitions – Janet McDonald (OAQPS)

• Alon Bakersfield Crude Oil Flexibility Project - Laura Yannayon (R9) and Matt Spangler (OAQPS)

• Piedmont Green Power, LLC - Terry Johnson (R4) and Janet McDonald (OAQPS)

• See: https://www.epa.gov/title-v-operating-permits/title-v-petition-database

2:45 pm Overview of Identified Issues (20 minutes per issue)

• Ameren US District Court Decision – Jon Knodel (R7)

• DTE II on Appeal Sixth Circuit Court Decision – Ethan Chatfield & Sabrina Argentieri (R5)

• Keystone PAL Issue – Gerallyn Duke (R3)

3:45 pm Around the Regions || Regional report out/policy decisions

3:55 pm Call wrap-up and action items – Stephanie Kordzi (R6)

Heads Up...

Region 5 will take the lead for Regional Issues on our March 1st call

Reminder || Please review your recent correspondence and e-mail for any significant or other precedent-setting documents to Jon Knodel or Ward Burns in Region 7 for inclusion in the NSR Policy and Guidance Database. **To join the Permit List Serve** || Send a blank email, from the email address you want added to the list serve, to subscribe-permit@lists.epa.gov

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	
vs.	)	Case No. 4:11 CV 77 RWS
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	

MEMORANDUM OPINION AND ORDER

"'Why don't you go up to the Range?' somebody said to me.
'The air is pure, and they have the best water on earth.'"

- W.P. Kinsella
Shoeless Joe

TABLE OF CONTENTS

INTRODUCTION ... 1

FINDINGS OF FACT ... 6

I. BACKGROUND CONCERNING THE DEFENDANT, THE RUSH ISLAND PLANT, AND THE APPLICABLE REGULATIONS ... 6

A. The Defendant ... 6

B. The Rush Island Coal-Fired Power Plant ... 6

C. Facts Concerning General Applicability of the Prevention of Significant Deterioration Program ... 7

D. Notice of the Violations Alleged in the Complaint ... 9

II. FACTS CONCERNING THE 2007 AND 2010 BOILER UPGRADES AT RUSH ISLAND UNITS 1 AND 2 ... 10

A. The Boiler Components at Issue and Their Role in Burning Coal to Generate Electricity ... 10

B. Operational Problems Leading up to the 2007 and 2010 Boiler Upgrades ... 16

1. Boiler tube leaks ... 19

2. Slagging and fouling ... 20

3. Pluggage ... 22

4. Availability losses caused by the replaced components prior to the 2007 and 2010 outages as reported to the Generating Availability Data System ... 32

5. Reduction in the maximum capability of Unit 2 prior to the 2010 outage ... 38

C. The Approval and Engineering Process for the 2007 and 2010 Major Modifications ... 41

D. Ameren Justified Replacing the Economizers, Reheaters, Lower Slopes, and Air Preheaters Because They Would Improve Operations and Allow the Units to Generate More ... 45

E. Implementation of the 2007 and 2010 Major Modifications ... 52

F. The Cost of the 2007 and 2010 Major Modifications ... 57

III. THE 2007 AND 2010 BOILER UPGRADES EACH RESULTED IN A SIGNIFICANT NET EMISSIONS INCREASE OF SO_2 WITHIN THE MEANING OF THE PSD REGULATIONS ... 58

A. Overview ... 59

B. GADS-Based Emissions Calculations for Rush Island Units 1 and 2 ... 61

1. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 1 ... 71

2. Rush Island Unit 1 actual emission increases ... 75

3. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 2 ... 78

4. Rush Island Unit 2 actual emission increases based on availability ... 82

C. Emissions Increases Based on Unit 2 Capability Analyses ... 84

1. The expected capability and efficiency impact of the Unit 2 boiler upgrade ... 85

2. Actual increases in Unit 2's capability ... 89

3. Dr. Sahu's emission calculations based on Unit 2's capacity increase ... 95

4. Nothing in Mr. Caudill's opinions negates Mr. Koppe's calculations of capability increases ... 95

D. PROSYM-BASED EMISSIONS CALCULATIONS ... 98

1. Production cost modeling at Ameren ... 98

2. Dr. Hausman's sensitivity analyses ... 101

a. Unit 1 sensitivity analysis ... 102

b. Unit 2 sensitivity analysis ... 103

3. Dr. Hausman's "with and without" analyses ... 103

a. Unit 1 analysis ... 105

b. Unit 2 analysis ... 106

IV. AMEREN HAS FAILED TO MEET ITS BURDEN TO ESTABLISH THE APPLICABILITY OF THE DEMAND GROWTH EXCLUSION 107

A. Background about the Market for Rush Island's Generation 107

B. Ameren's Failure of Proof Regarding Demand Growth as a Cause of Increased Emissions 111

V. AMEREN'S NSR EMISSION ANALYSES 114

A. Ameren Performed No Pre-Project NSR Analysis for Either Project 116

1. Rush Island Unit 1 116

2. Rush Island Unit 2 117

B. Ameren's Post Hoc Reasonable Possibility Analysis is Substantively Flawed 121

1. Ameren's calculations fail to model all of the performance improvements expected from the boiler upgrades 121

2. Ameren's capable of accommodating approach 122

3. No analysis of relatedness 124

C. Nothing in Ms. Ringelstetter's Analyses Excuses Ameren's Failure to Perform Appropriate NSR Projections 126

1. Ms. Ringelstetter failed to address relatedness for either unit 126

2. Ms. Ringelstetter's Unit 1 analysis relies on faulty assumptions 128

a. Background regarding ancillary services 128

b. Ms. Ringelstetter's modeling choice 131

VI. THE 2007 AND 2010 BOILER UPGRADES TRIGGERED TITLE V REQUIREMENTS. 132

CONCLUSIONS OF LAW 132

I. OVERVIEW 132

II. THE UNITED STATES PROVED THAT AMEREN VIOLATED THE PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V PROVISIONS OF THE CLEAN AIR ACT 133

A. Undisputed Elements of Proof 133

B. The Projects Should Have Been Expected to Cause—and Did Cause—Emissions Increases 134

1. Legal standard 134

2. The evidence shows that Ameren should have expected an emissions increase related to each project, and such an emissions increase occurred 137

a. The Koppe-Sahu emissions calculations show a predicted increase at Unit 1 and were confirmed by an actual increase 138

b. The Koppe-Sahu emissions calculations show a predicted increase at Unit 2 and were confirmed by an actual increase 143

3. Dr. Hausman used Ameren's modeling to quantify the emissions impact from the projects 148

4. The evidence shows that efficiency improvements would not prevent emissions from increasing as a result of the projects 151

5. Conclusion: The emissions evidence shows an increase related to the projects should have been expected and actually occurred 154

C. Ameren Also Violated Title V 155

III. AMEREN'S DEFENSES AND CRITIQUES OF THE UNITED STATES' EVIDENCE FAIL 156

A. The Projects were not Routine Maintenance 156

1. Legal standard 157

2. The boiler refurbishments at each Rush Island unit constitute one project for routine maintenance purposes 158

3. The projects do not qualify for the routine maintenance exemption 160

a. Nature and extent 160

b. Purpose 161

c. Frequency 162

d. Cost 163

4. Conclusion: the projects cannot be considered routine 163

B. The Emissions Increases Cannot Be Set Aside Based on the Demand Growth Exclusion. 164

1. Ameren's experts confirm that demand was not projected to—and did not—cause the pollution increases at Rush Island 165

2. Ameren's evidence does not address what portion of the units' projected or actual emissions increases were "unrelated" to the projects 166

3. Ameren's other demand growth arguments fail 169

4. Emissions resulting from operations that would not have been possible but for the boiler upgrades cannot be considered "unrelated" to those boiler upgrades 172

C. Ameren's New Source Review Analyses Are Fatally Flawed and Cannot Provide Safe Harbor from Liability 176

1. Ameren does not have a legitimate process for assessing PSD applicability 176

2. Unit 1 179

3. Unit 2 181

EVIDENTIARY ISSUES FROM TRIAL 184

I. AMEREN'S MOTIONS TO STRIKE TESTIMONY AND EVIDENCE 184

A. Ameren's Motions to Strike Mr. Koppe and Dr. Sahu's Testimony and Evidence Concerning the Causation of Actual Emissions Increases 184

B. Ameren's Motion to Strike Dr. Hausman's Testimony Criticizing Ms. Ringelstetter's Opinions 187

II. THE UNITED STATES' MOTION TO CURTAIL RE-LITIGATION OF THE LAW OF THE CASE 187

CONCLUSION 188

INTRODUCTION

Plaintiff the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), filed this suit against defendant Ameren Missouri ("Ameren") on January 12, 2011. The United States alleges that Ameren committed various violations of the Clean Air Act, 42 U.S.C. § 7401 *et seq.*, the Missouri State Implementation Plan, and Ameren's Rush Island Plant Title V Permit when it allegedly undertook major modifications at its Rush Island Plant in Festus, Missouri without obtaining the required permits. For the reasons that follow, I conclude the United States has established that Ameren violated the Clean Air Act and its operating permit by carrying out the Rush Island projects without obtaining the required permits, installing best-available pollution control technology, and otherwise meeting applicable requirements.

The modern Clean Air Act was passed in 1970 in order "'to speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the nation is wholesome once again.'" *United States v. Duke Energy Corp.* ("*Duke Energy 2010*"), No. 1:00 CV 01262, 2010 WL 3023517, at *2 (M.D.N.C. July 28, 2010) (quoting H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356). By 1977, Congress had determined that earlier programs "did too little" to achieve air quality goals and added the New Source Review program ("NSR"), including the Prevention of Significant Deterioration ("PSD") provisions at issue in this case. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007) ("*Duke Energy 2007*"); *New York v. EPA*, 413 F.3d 3, 12-13 (D.C. Cir. 2005). The PSD program is designed to *prevent* significant increases in pollution, an objective built into the very name of the program. *United States v. Ameren Missouri ("Ameren SJ Decision")*, Case No. 4:11 CV 77 RWS, 2016 WL 728234, at *13 (E.D. Mo. Feb. 24, 2016).

The program is designed to prevent future significant increases in pollution, in part, by requiring major-emitting facilities to employ state-of-the-art pollution controls.

When it enacted the PSD program, Congress required all new major-emitting facilities to comply with PSD requirements by installing state-of-the-art pollution controls at the time of construction. Recognizing the expense and burden of installing such controls, however, Congress did not require facilities then in existence to immediately install pollution controls. Rather, Congress allowed these facilities to continue to operate without installing such controls on the condition that if they ever modified their facilities, they would calculate the impact of those modifications, report the planned modifications to the EPA, obtain the requisite permits, and install the required pollution control technologies at that time. PSD rules apply to "major modifications," which occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. *See Ameren SJ Decision*, 2016 WL 728234, at *4. An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Congress enacted these modification provisions to ensure that facilities that were grandfathered into the program would not be allowed "perpetual immunity" from PSD's requirements. *Ala. Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979). Under the PSD program:

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006).

Ameren's Rush Island plant includes two coal-fired electric generating units, Units 1 and 2. These units went into service in 1976 and 1977 and were grandfathered into the PSD program. Neither unit has air pollution control devices for SO_2. The Rush Island plant currently emits about 18,000 tons of SO_2 per year. The Rush Island units are big sources of pollution, so even small performance improvements or increases in unit availability can lead to a 40-ton increase in SO_2. It only takes an availability improvement of 0.3% or an additional 21 hours of operation at full power for the Rush Island units to emit more than 40 tons of SO_2.

By 2005, some of the major boiler components in Units 1 and 2 were causing problems that forced Ameren to frequently take the units out of service and made the units underperform, reducing the amount of electricity Ameren could generate and sell from the units. Ameren decided to fix these problems by replacing the problem components with new, redesigned components. Courts in PSD enforcement actions have long recognized that "[i]f the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," burning more coal and emitting more pollution. *United States v. Ala. Power Co.*, 730 F.3d 1278, 1281 (11th Cir. 2013); *see also United States v. Ohio Edison*, 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). When these conditions occur, as they did here, they trigger a utility's obligation to conduct PSD review, secure the appropriate permits, and install required pollution controls.

This standard for assessing PSD applicability was well-established when Ameren planned its component replacement projects for Units 1 and 2. Ameren's testifying expert conceded that the method used by the United States' experts—which showed that Ameren should have expected the projects to trigger PSD rules—has been "well-known in the industry" since 1999.

But Ameren did not do any quantitative PSD review for the project at Unit 1 and performed a late and fundamentally flawed PSD review for Unit 2. And Ameren did not report its planned modifications to the EPA, obtain the requisite permits, or install state-of-the-art pollution controls. Instead, Ameren went ahead with the projects, spending $34 to $38 million on each unit to replace the problem components. It executed these projects as part of "the most significant outage in Rush Island history," taking each unit completely offline for three to four months. Ameren's engineers justified the upgrade work to company leadership on the basis that the new components would eliminate outages and the investment would be returned in recovered operations.

The evidence shows that by replacing these failing components with new, redesigned components, Ameren should have expected, and did expect, unit availability to improve by much more than 0.3%, allowing the units to operate hundreds of hours more per year after the project. And Ameren should have expected, and did expect, to use that increased availability (and, for Unit 2, increased capacity) to burn more coal, generate more electricity, and emit more SO_2 pollution.

Now that the projects have been completed, the evidence shows that Ameren's expected operational improvements actually occurred. Replacement of the failing components increased availability at both units by eliminating hundreds of outage hours per year. Unit 2 capacity also increased. Ameren's employees have admitted that those availability increases would not have happened but for the projects. As a result of the operational increases, the units ran more, burned more coal, and emitted hundreds of tons more of SO_2 per year.

In response to these projects, the United States filed this suit against Ameren, alleging that Ameren violated the Clean Air Act, the Missouri State Implementation Plan, and Ameren's

Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the required permits, installing state-of-the-art pollution control technology, or otherwise complying with applicable requirements.

Previously, in ruling on the parties' summary judgment motions, I set out several of the legal standards at issue in this case. *See Ameren SJ Decision*, 2016 WL 728234, at *13 (ruling on the parties' various motions for partial summary judgment and evidentiary motions); *United States v. Ameren Missouri*, 158 F. Supp. 3d 802, 804 (E.D. Mo. 2016) (denying Ameren's motion for full summary judgment). I held a twelve day non-jury trial beginning on August 22, 2016. The parties filed post-trial briefs and proposed findings of fact and conclusions of law on September 30, 2016 and argued outstanding evidentiary issues that were raised at trial. On October 12, 2016, the parties filed responses to each other's post-trial briefs.

After consideration of the testimony given at trial, the exhibits introduced into evidence, the parties' briefs, and the applicable law, I make the following findings of fact and conclusions of law, which largely adopt those proposed by the United States. As discussed below, I conclude the United States has established that Ameren should have expected, and did expect, the projects at Rush Island to increase unit availability (and, for Unit 2, to increase capacity), which enabled Ameren to run its units more, generate more electricity, and emit significantly more pollution. The United States has also established that Ameren actually emitted significantly more pollution as a result of the projects. Ameren has failed to establish that either the routine maintenance or demand growth defenses apply to shield it from liability. As a result, I conclude that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act.

FINDINGS OF FACT

I. BACKGROUND CONCERNING THE DEFENDANT, THE RUSH ISLAND PLANT, AND THE APPLICABLE REGULATIONS

A. The Defendant

1. Defendant Ameren Missouri is a Missouri corporation. Defendant's incorporated name is Union Electric Company, but Defendant conducts business under the name Ameren Missouri. Answer to Third Amended Complaint ("Answer"), at ¶ 10 (ECF No. 250); Joint Stipulations of Fact ("Joint Stip."), at ¶ 1 (ECF No. 743).

2. As a corporate entity, Ameren is a "person" within the meaning of the Clean Air Act Section 302(e), 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2). Answer, at ¶ 11; Joint Stip., at ¶ 2.

3. At all times relevant to this case, Ameren has been the owner and/or operator of the Rush Island Plant in Festus, Jefferson County, Missouri. Answer, at ¶¶ 12, 57; Joint Stip., at ¶ 3.

B. The Rush Island Coal-Fired Power Plant

4. The Rush Island coal-fired power plant ("Rush Island Plant") consists, in part, of Units 1 and 2, which are coal-fired electric generating units. Rush Island Units 1 and 2 went into commercial service in 1976 and 1977, respectively. Answer, at ¶¶ 13, 59; Joint Stip., at ¶ 4.

5. The Rush Island units were originally designed to have an approximately 30-year life. Testimony of U.S. Power Plant Expert Bill Stevens, Trial Transcript Volume ("Tr. Vol."), 1-B 50:24-51:4, 69:4-11. The components of large units like the Rush Island units typically have a life of between 30 and 40 years. Stevens Test., Tr. Vol. 1-B 81:19 – 82:1.

6. The Rush Island units were designed as baseload units, meaning they generally operate every hour that they are available to run. Design Data Report (Pl. Ex. 297), at AUE-00022523, 22526; Testimony of Retired Ameren Vice President Charles Naslund, Tr. Vol. 6-A, 55:4-7; Anderson Dep., Dec. 4, 2013, Tr., 63:21 – 64:6; Pope Dep., Sept 20, 2013, Tr. 121:18 – 122:11; Testimony of U.S. Utility System Modeling Expert Dr. Ezra Hausman, Tr. Vol. 4-B, 26:15-10; Testimony of EPA Engineer Jon Knodel, Tr. Vol. 1-A, 75:16 – 75:24; 76:21–76:25.

7. The Rush Island units are among Ameren's most cost-effective units and carry much of the system load. Retired Ameren executive vice president Charles Naslund described the units as "two workhorses." Naslund Test., Tr. Vol. 6-A, 50:3-12.

8. Burning coal at Rush Island Units 1 and 2 generates combustion gases containing sulfur dioxide ("SO_2"). The SO_2 gases at Rush Island Units 1 and 2 are passed through a smokestack directly to the atmosphere, as neither unit has air pollution control devices for SO_2. Testimony of U.S. Emissions Expert Ranajit Sahu, Tr. Vol. 5, 43:9 – 44:24; Knodel Test., Tr. Vol. 1-A, 73:7 – 73:9.

9. The Rush Island plant currently emits about 18,000 tons per year of SO_2. Knodel Testimony, Tr. Vol. 1-A, 73:16 – 73:18. If Ameren operated scrubbers at Rush Island that achieved emissions reductions comparable to other plants in the region that currently operate scrubbers, SO_2 emissions would be reduced to several hundred tons per year. Knodel Test., Tr. Vol. 1-A, 108:3 – 108:5.

C. Facts Concerning General Applicability of the Prevention of Significant Deterioration Program

10. The Clean Air Act's New Source Review ("NSR") program consists of a Prevention of Significant Deterioration ("PSD") program and a Nonattainment New Source

Review program. The PSD program applies in areas that are in attainment with the National Ambient Air Quality Standards ("NAAQS") for a particular pollutant or are unclassifiable. 42 U.S.C. §§ 7471, 7475. Knodel Test., Tr. Vol. 1-A, 52:11 - 53:4.

11. The Rush Island Plant is located approximately 50 miles south of St. Louis, Missouri, in the southern tip of Jefferson County, which is currently designated as in nonattainment with the NAAQS for SO_2. Knodel Test., Tr. Vol. 1-A, 53:8 – 53:15 At the time of the 2007 and 2010 projects at issue in this case, Jefferson County was classified as in attainment with the NAAQS for SO_2. Answer, at ¶ 19.

12. At all times relevant to this case, the Rush Island Plant has been a fossil-fuel fired steam electric plant of more than 250 million British thermal units per hour heat input, and has had the potential to emit more than 100 tons per year of SO_2. The Rush Island Plant is a "major emitting facility" as defined by 42 U.S.C. § 7479(1), and a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1) and 42 U.S.C. § 7602(j). Answer, at ¶¶ 58, 59; Knodel Test., Tr. Vol. 1-A, 53:16 – 54:1.

13. Rush Island Units 1 and 2 are each a "major emitting facility" as defined by 42 U.S.C. § 7479(1), a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1), and an "electric utility steam generating unit" as defined by 40 C.F.R. § 52.21(b)(31). Joint Stip., at ¶ 5.

14. At the time of the 2007 and 2010 projects, the applicable EPA-approved Missouri PSD regulations were found in the 2003 version of 40 C.F.R. § 52.21, as incorporated into Missouri Rule 10 C.S.R. 10-6.060. Before a major source of air pollution located in such an area designated as in attainment with the NAAQS undergoes a "major modification," the owner or operator of the source must obtain a PSD permit that imposes emission limits. *See* January 21,

2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2), (j); 71 Fed. Reg. 36,486 (June 27, 2006).

15. The PSD regulations define "major modification" as "any physical change … that would result in" a significant net emission increase in actual emissions from a major stationary source. *See* January 21, 2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2)(i).

16. Under the PSD regulations, a "physical change" does not include "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(a)(2)(iii).

17. Under the PSD regulations, a "significant" increase in SO_2 is 40 tons per year. 40 C.F.R. § 52.21(b)(23)(i).

D. Notice of the Violations Alleged in the Complaint

18. The EPA issued a Notice of Violation on January 26, 2010, and issued amended Notices of Violation on October 14, 2010 and May 27, 2011. The Notices of Violation identified, *inter alia*, the alleged violations arising from the 2007 and 2010 major modifications of Rush Island Units 1 and 2 that are at issue in this case. Answer, at ¶ 6; Joint Stip., at ¶ 6.

19. The Notices of Violation were provided to Ameren and the State of Missouri, in accordance with 42 U.S.C. § 7413(a). Answer, at ¶ 6; Joint Stip., at ¶ 7.

20. The United States filed its original Complaint on January 12, 2011 (ECF No. 1), an Amended Complaint on June 28, 2011 (ECF No. 36), a Second Amended Complaint on October 30, 2013 (ECF No. 165), and a Third Amended Complaint on April 24, 2014 (ECF No. 249). The Amended Complaint, Second Amended Complaint, and Third Amended Complaint alleged, *inter alia*, violations arising from the 2007 and 2010 major modifications of Rush Island

Units 1 and 2 that are at issue in this case, and were filed more than 30 days after notice of the violations was provided as required by 42 U.S.C. § 7413(a). Joint Stip., at ¶ 8.

21. The United States provided notice of the commencement of this action to the State of Missouri, as required by 42 U.S.C. § 7413(b). Knodel Test., Tr. Vol. 1-A, 87:4 - 87:23.

II. FACTS CONCERNING THE 2007 AND 2010 BOILER UPGRADES AT RUSH ISLAND UNITS 1 AND 2

22. The major modifications in this case arise from construction projects undertaken by Ameren in 2007 and 2010 at Rush Island Units 1 and 2. The 2007 major modification occurred at Rush Island Unit 1 during a major boiler outage that began on February 17, 2007 and ended on May 28, 2007. The 2010 major modification occurred at Rush Island Unit 2 during a major boiler outage that began on January 1, 2010 and ended on April 9, 2010. Stevens Test., Tr. Vol. 2-A, 24:9 -24:15; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

A. The Boiler Components at Issue and Their Role in Burning Coal to Generate Electricity

23. Rush Island Units 1 and 2 each include a large boiler where coal is burned to convert water into steam. The boilers are comprised of a number of major components, including the economizers, reheaters, lower slope panels, and air preheaters at issue. The economizer, reheater, and lower slope panels are each comprised of bundles of steel tubes designed to carry high-temperature, high-pressure steam to the turbines. Altogether, the boilers in large coal-fired units like those at Rush Island are constructed of hundreds of miles of tubing. Exposing the steel tube bundles in the major boiler components to the heat from burning coal converts water into steam. The steam is sent to the turbines, including a high pressure turbine, an intermediate pressure turbine, and a low pressure turbine. The turbines spin a generator, which

produces electricity. Unlike the tubular boiler components, the air preheater does not consist of steel tube bundles; it consists of metal heat exchanging surfaces that preheat additional air used for combustion of coal in the boiler. Stevens Test., Tr. Vol. 1-B, 55:9 - 55:13, 57:13 - 61:6; *see also* Welcome to Rush Island Plant Presentation (Pl. Ex. 35), at AM-02253169-173.

24. The Rush Island boiler house is approximately 270 feet tall from the ground to the rooftop. Stevens Test., Tr. Vol. 1-B, 95:10-16. Each boiler is approximately 230 feet tall. Stevens Test., Tr. Vol. 1-B, 95: 10-18; Welcome to Rush Island Presentation, (Pl. Ex. 35), at AM-02253171. Each furnace is approximately 60 feet wide and 50 feet deep. Stevens Test., Tr. Vol. 1-B, 96:2-5.

25. The specific boiler components at issue in the major modifications are the economizer, reheater, lower slopes, and air preheaters that were replaced at Rush Island Unit 1 in 2007, and the economizer, reheater, and air preheaters that were replaced at Rush Island Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 81:9 - 82:8; Stevens Test., Tr. Vol. 1-B, 46:2-12.

26. The Rush Island economizers are located in the convection section of each boiler. Stevens Test., Tr. Vol. 2-A, 29:11-24. The purpose of the economizer, which is the first tubular heat exchanging component in the boiler, is to take heat from the hot gases in the boiler and transfer it to high pressure boiler feedwater. When it leaves the economizer, the water is close to turning into steam. It then flows to a steam drum before being circulated through waterwall tubes that form the walls of the boiler furnace, and on to a section of the boiler known as the superheating section, before being sent as steam to the high pressure turbine. Stevens Test., Tr. Vol. 1-B, 58:12 – 60:6.

27. Each economizer at Rush Island Unit 1 and 2 weighed approximately 600 tons. Stevens Test., Tr. Vol. 2-A, 34:22 – 35:7. The original Unit 1 and Unit 2 economizers had

identical designs. They each had two banks – an upper and a lower bank – with 276 assemblies per bank, and had a spiral-finned design, with a staggered arrangement. The diameter of each tube was 1.75 inches. Stevens Test., Tr. Vol. 2-A, 29:25 - 30:18; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276; Ameren's Response to Request for Admission ("RFA") Nos. 362, 364, 365, 367 (ECF. No. 785-1).

28. The Rush Island reheaters are located at the top of each boiler's furnace. Stevens Test., Tr. Vol 2-A, 41:14-42:13. The purpose of the reheater is to reheat steam after it has passed through the high pressure turbine, before being sent back to the intermediate and low pressure turbines. Stevens Test., Tr. Vol. 1-B, 60:7 – 60:17.

29. The original Rush Island reheaters each had a front section and a rear section. The front section had 72 side-by-side assemblies, each of which was over 50 feet tall. The front assemblies were spaced on ten inch centers. The original front section had a sloped bottom, which created a close clearance between the bottom of the reheaters' front section and each boiler's nose. The rear section had 145 assemblies, each of which was around 26 feet tall. Both the front and rear reheater sections were spaced, not platenized, meaning there was no material that connected one tube to the next. Stevens Test., Tr. Vol. 2-A 42:2 - 43:2; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080428; RFA Nos. 386, 387, 389, 390.

30. Rush Island's lower slope tubes are part of the waterwall tubes and are located in the bottom of the furnace area of the boiler. Stevens Test., Tr. Vol. 1-B, 61:15-24, Tr. Vol. 2-A, 51:2 -51:19.

31. In addition to the economizers, reheaters, and lower slopes, the other primary boiler components at issue in this case are the air preheaters, which help warm combustion air entering the boiler. Forced draft ("FD") fans are used to push combustion air into the boiler, and

before entering the furnace the cold combustion air passes through the lower portion of the air preheater. Once in the furnace, the air mixes with pulverized coal and creates flue gas which heats the water and steam in the boiler tube components. Among other things, the flue gas contains tiny particles of ash known as flyash. Stevens Test., Tr. Vol. 1-B, 57:13 – 58:11; Tr. Vol. 2-A, 56:21-57:11.

32. The hot flue gas resulting from coal combustion flows up through the furnace and then from the back pass of the boiler down through the top of the air preheater, before going to the electrostatic precipitator and then being sucked out by induced draft ("ID") fans and sent up the stack. During this process, the air preheater rotates, allowing the hot flue gas exiting the boiler to warm up the forced draft air that is entering the boiler. Stevens Test., Tr. Vol. 2-A 13:10-14, 56:21-58:8; Testimony of U.S. Power Plant Expert Robert Koppe, Tr. Vol. 3-A, at 16:16-17:2.

33. Rush Island Units 1 and 2 each have two air preheaters. Each air preheater is approximately 40 feet tall and is located approximately 100 feet from ground level. Stevens Test., Tr. Vol. 2-A 13:10-14, 67:21-68:5. Each air preheater weighed at least a couple hundred tons. Stevens Test., Tr. Vol. 2-A 59:3-6.

34. The original Rush Island air preheaters were Ljungstrom regenerative air preheaters. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275. Each original air preheater had three layers: a hot layer, an intermediate layer, and a cold layer. RFA Nos. 329, 332. Each layer was made up of air preheater baskets of various sizes. There were 216 hot end baskets, and each basket was 42 inches thick. There were 216 intermediate end baskets, and each basket was 16 inches thick. RFA No. 333, 334. There were 24 cold end baskets, and each basket was 12 inches thick. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21; RFA No. 335.

35. Because the tubes that comprise the economizers, reheaters, and lower slopes are in constant contact with flue gas and/or combusting coal, these tubes are subject to deterioration over the life of the boiler and eventually develop leaks, which require repair or replacement. When the tubes degrade and the walls become too weak, the high pressure steam or water can burst through, resulting in a boiler tube leak. Large leaks require a unit to shut down while the portion of the tube that ruptured is repaired, which typically lasts two to three days. Koppe Test., Tr. Vol. 3-A, at 14:16-15:9; Stevens Test., Tr. Vol. 1-B, 65:15 - 66:7.

36. Typically, the length of tube replaced when fixing a boiler tube leak would be on the order of several feet of tube. Stevens Test., Tr. Vol. 1-B, 79:4 - 79:19. Such repairs would be part of the day-to-day responsibility of plant maintenance staff and would involve no design changes to the component. Stevens Test., Tr. Vol. 1-B, 65:15 – 66:15, 69:4 – 69:11.

37. Similarly, on occasion some cold end air preheater baskets might need to be replaced due to corrosion. Stevens Test., Tr. Vol. 2-A, 58:14-21.

38. It is well known in the industry that a well-designed section of new boiler tubes should have almost no leaks at all for the first 20 years, before the tubes eventually begin to wear out and start to fail. Koppe Test., Tr. Vol. 3-A 50:11-50:16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24 (Ameren was not expecting any tube leaks with the new economizer).

39. In light of the harsh conditions in which they operate, boiler components typically have a finite design life of between 20 to 40 years of operation. Stevens Test., Tr. Vol. 1-B 83:5-15. At that point, routine maintenance may no longer be sufficient to maintain desired operations, and an alternate approach may be required to optimize and extend the life of the unit. Vol. 1-B, Stevens Test., 82:2-20.

40. As a result, if a utility like Ameren wants to operate a boiler like the Rush Island boilers beyond 25 to 35 years, one strategy would be to replace the major boiler components, including the reheater. Stevens Test., Tr. Vol. 1-B 83:5-21, 84:5-6. Likewise, an economizer should be expected to last approximately 35 years and lower slope tubes should be expected to last approximately 40 years. Stevens Test., Tr. Vol. 1-B 83:22-84:4, 84:7-8. Ameren's expert witness, Mr. Jerry Golden, similarly testified that the typical life of a reheater is about 30 years, the typical life of an economizer is about 35 years, and the typical life of a lower furnace is about 40 years. Golden Test., Tr. Vol. 8-A, 18:2 – 18:11.

41. Life extension activities historically have been considered in the utility industry to be different than typical maintenance activities. The distinction was explained by Mr. Stevens, and is also discussed in an authoritative engineering text published by Babcock and Wilcox known as the "Steam Book." Stevens Test., Tr. Vol. 1-B 76:7 – 76:16, 78:4-7, 80:6-17.

42. According to the Steam Book, prior to the 1980s, it was assumed that older plants would be torn down to make room for newer, larger, more efficient units, and it was common to retire plants after 35 to 40 years of service. That assumption changed when utilities began to engage in life extension activities. The concept of "Life Extension and Upgrades" is discussed in a chapter in the Steam book by that name, while routine maintenance is discussed separately. Golden Test., Tr. Vol. 8-A, 32:16-33:8; Stevens Test., Tr. Vol. 1-B, 78:4-79:3.

43. The Steam Book describes a case-study involving the replacement of an economizer as a "life extension" project. In that life extension case study, a staggered economizer at a coal-fired generating unit was experiencing pluggage and gas flow resistance, resulting in erosion and tube failures. It was replaced with a new, redesigned, in-line

economizer, which alleviated the operational problems and allowed for higher availability and reliability. Stevens Test., Tr. Vol. 1-B 84:19-87:19.

44. By contrast, typical maintenance activities on coal-fired fired boilers are those done on a day-to-day basis to keep the power plant running in its current condition. Such typical maintenance includes things like replacing small sections of tubing, not replacing entire boiler components. Stevens Test., Tr. Vol. 1-B 64:15-66:15; 77:23-78:3, 78:20-79:19, 80:6-12.

45. Similarly, Ameren's Work Order Procedure Manual defines routine maintenance activities as those that "relate to work performed regularly by Ameren employees or contractors on an ongoing basis in the customary and normal course of business to operate or maintain facilities and equipment." Ameren Work Order Procedure (Pl. Ex. 7), at AM-00066968; Stevens Test., Tr. Vol. 1-B 71: 15-72:7. Such routine activities are not subject to the requirements of Ameren's Work Order Procedures. Pl. Ex. 7, at AM-00066960, 66968; Stevens Test., Tr. Vol. 1-B 72:9-14; Moore Dep., Sept. 16, 2014, Tr. 22:11-22.

46. Ameren's Administrative Design Control Manual provides that any activity that changes "any design or operating feature of the plant that is described by drawings or other design documents" is not considered routine maintenance. Ameren Administrative Procedure Design Control Manual (Pl. Ex. 495), at AM-0223699; Stevens Test., Tr. Vol. 2-A, 70:24-71:2.

B. Operational Problems Leading up to the 2007 and 2010 Boiler Upgrades

47. The Rush Island Units were originally designed to burn Southern Illinois Bituminous Coal. Rush Island Resurfacing Study (Pl. Ex. 20), at AM-00499384; Stevens Test., Tr. Vol. 1-B, 100:24 -101:4, Tr. Vol. 2-A, 92:10-92:15. Around 1990, Rush Island began to burn coal from the Powder River Basin in Wyoming, known as PRB coal. Stevens Test., Tr. Vol. 1-B, 101:5-14. By 1995, the Rush Island units were burning 100 percent PRB coal. Stevens

Test., Tr. Vol. 1-B, 101:15-20; Meiners Test., Tr. Vol. 7-A, 102:10-12; Meiners Dep., April 8, 2014, Tr. 237:9-238:11; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275; Project Approval Package (Pl. Ex. 3), at AM-00072837.

48. Ameren chose to switch to PRB coal, which has less sulfur, in order to comply with the Clean Air Act's separate "Acid Rain" rules. As Ameren explained in an internal 1992 Acid Rain "Compliance Strategy" document, "a significant advantage of a fuel switch strategy is that it delays an irreversible decision to construct scrubbers." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020365; Knodel Test., Tr. Vol. 1-A, 102:16-21.

49. The Acid Rain rules are part of a program under Title IV of the 1990 Clean Air Act Amendments designed to reduce by about 50% precursors of acid rain, or acid deposition, from coal-fired power plants. These pollutants include SO_2 and nitrogen oxides. Knodel Test., Tr. Vol. 1-A, 55:13-19; *see* 42 U.S.C § 7651 *et seq*.

50. According to retired Ameren senior vice president Charles Naslund, PRB coal is the cheapest fuel option for the Rush Island plant, and Ameren has the cheapest fuel costs in the regional transmission area, known as the Midcontinent Independent System Operator ("MISO") area. "So when I bid in my units, basically my units are always picked up pretty much baseload because I'm the cheapest." Naslund Dep., Sept. 18, 2014, Tr. 144:17 – 145:7; Knodel Test., Tr. Vol. 1-A, 104:22-105:09. The economic advantage provided by burning cheaper coal than their competitors means Rush Island Units 1 and 2 run a higher percentage of the time. Naslund Test., Tr. Vol. 6-A, 48:7-49:3.

51. Although PRB coal was cheaper and had less sulfur, it differed in other important characteristics, including having a lower heating value and higher moisture content, meaning that

more coal needed to be burned to achieve the same output from the units. Stevens Test., Tr. Vol. 1-B, 101:21-102:15; Pope Dep., Sept. 20, 2013, Tr. 71:18-72:9. Because the Rush Island plant was not designed for coal with these characteristics, Ameren knew that switching to PRB would eventually cause operational problems at the units. Meiners Dep., April 8, 2014, Tr. 237:9-238:1; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:12. For instance, Ameren's Acid Rain Compliance Strategy specifically identified the fact that "the low heat content and the higher moisture of these coals generally result in operational problems that reduce capability." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020397.

52. The anticipated problems from switching to PRB coal for which the units were not designed were realized, causing related operational problems across the entire boiler. These problems worsened over time, and by the mid-2000's, these components were also suffering from additional operational problems due to age-related deterioration, including tube leaks in the boiler components. Fred Pope, Rush Island's former General Manager of Engineering and Technical Services, said Ameren took interim measures to "defer as long as we could the potential component replacements that…we anticipated would eventually come as the result of individual components reaching the end of their life, and we recognized that when that occurred, we would…..adjust the design of those components…to accommodate western coal." Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

53. As described further below, these operational problems included boiler tube leaks, slagging, fouling, and plugging, which adversely affected the economizers, reheaters, lower slopes, and air preheaters. These problems, which were extensively described in Ameren's documents, forced each of the units to be completely shut down (in outages) for periods of time,

or to have their electricity generation limited to less than full power (derated) for periods of time. Stevens Test., Tr. Vol. 1-B 102:16-102:24, 105:18-105:20, 107:6 - 109:13; Tr. Vol. 2-A, 7:16-8:20, 59:7-60:22, 63:22-65:7; Koppe Test., Tr. Vol. 3-A, 14:5-15; *see* Project Approval Package (Pl. Ex. 1), at AM-0072580 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 1), 72585 (recounting that "switch to 100% PRB coals has caused flyash pluggage" and noting boiler tube leaks at Unit 1), 590 (describing need for Unit 1 replacements following switch to PRB coal); Project Approval Form (Pl. Ex. 2), at AM-00072829 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831 & 837 (same statements for Unit 2); Project Approval Package (Pl. Ex. 6), at AM-00072912 (describing "major boiler modifications" at both units to address components "experiencing an increase in tube leaks" and planned redesigns for PRB coal); July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters); September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (Unit 2 air preheaters "have continued to foul"); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322-323 (describing problems in Unit 2 reheater and economizer following switch to PRB coal); Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276-279 (describing problems in Unit 1 and 2 boiler components); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966724-725, 731-736, 740-742, 745, 750-753 (describing problems in components).

1. Boiler tube leaks

54. As discussed above, boiler tube leaks occur in tubular components such as economizers, reheaters, and lower slopes, and large leaks require a unit to shut down for repairs which typically last two to three days. FOF 35.

55. The rates of boiler tube failures are generally unlike the failure rates that may occur in other equipment in a boiler. Other boiler equipment tends to have failure rates that stay constant with time as long as the utility keeps up with its maintenance. But as boiler tube components degrade and reach the end of their useful life, their failure rates increase with time and become repetitive given the miles of deteriorated tubing, any inch of which can fail. As the component reaches the end of life, the failures will keep increasing even though the utility repairs specific leaks. Koppe Test., Tr. Vol. 3-A, 52:8-54:15.

56. The Rush Island Units were experiencing boiler tube leaks in the years leading up to the 2007 and 2010 major boiler outages, particularly in the three boiler tube components at issue in this case. Koppe Test., Tr. Vol. 3-A 14:5-15. As Ameren's documents described the situation for the Rush Island plant as of 2005, "[t]here were a total of 10 reheat leaks in the reheaters in 2004 alone" along with "a total of 4 economizer tube leaks" and "12 lower slope tube leaks." Project Approval Package (Pl. Ex. 3), at AM-00072837; *see also id.* at AM-00072831 (noting problems that were "causing tube leaks" in the lower slopes and that "[t]here have been tube leaks in the economizer sections and reheater pendants"); Project Approval Package (Pl. Ex. 1), at AM-00072585, 72590 (identical document for Unit 1); 2008 State of the System Presentation (Pl. Ex. 15), at AM-00196730-735 (presentation identifying lost megawatt-hours from boiler tube leaks at both units).

2. Slagging and fouling

57. Slagging is the accumulation of liquid ash on the walls of the furnace and on components that are located at the top of the furnace, including superheaters and reheaters. Slag condenses or solidifies, eventually becoming like rock or concrete. Slag can bridge between tubes causing plugging, which limits flow through the unit. Slag can also fall down through the

furnace, causing tube leaks in the lower slope tubes. Stevens Test., Tr. Vol. 1-B, 104:23 – 105:17; Tr. Vol. 2-A, 51:02-52:25

58. Slag buildup on the reheaters would fall to the bottom of the furnace, causing damage to the lower slope tubes. Stevens Test., Tr. Vol. 2-A 44:1-21; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080278; Boll Dep., Sept. 5, 2014, Tr. 68:11-70:5. The slag falls caused "a vast number of gouges" on the lower slope tubes, which would often require a unit shutdown to repair. Pl. Ex. 28, AM-00966722, at 745. The slag falls at the Rush Island units were at times as large as an automobile. Stevens Test., Tr. Vol. 2A, 54:2-14; Boll Dep., Sept. 5, 2015, Tr. 69:22-70:5. In addition, the lower slope tubes were experiencing problems related to 30 years of exposure to liquid ash and molten slag. Stevens Test., Tr. Vol. 2-A 51:20 – 52:25, 54:2 – 14; Pl. Ex. 28, at AM-00966745; Project Approval Package (Pl. Ex. 1), at AM-00072585; Project Approval Package (Pl. Ex. 3), at AM-00072831.

59. Before the 2007 major boiler outage, Ameren undertook efforts to repair the tube leaks caused by falling slag. For instance, Ameren would pad-weld over areas eroded by flowing slag and would replace leaking sections of tubes. However, because the buildup of slag was a recurring problem that was not being controlled adequately, problems continued. Stevens Test., Tr. Vol. 2-A 54:15-55:8.

60. Fouling is the deposit of solid particles of ash on heat transfer surfaces. When fouling builds up on itself, it can plug the gas flow path between boiler tubing, limiting gas flow across the component, and through the unit. Fouling also leads to higher velocity gas flows through the areas that are not plugged, which causes erosion and tube failures. Stevens Test., Tr. Vol 1-B, 102:16-103:23, Tr. Vol. 2-A, 32:7-32:23.

3. Pluggage

61. Pluggage at Rush Island Units 1 and 2 occurred in the reheaters and economizer boiler tube components and in the air preheaters. Pluggage in boiler tube components occurs when ash material bridges the spaces between tubes, limiting gas flow. Stevens Test., Tr. Vol. 1-B, 103:24 - 104:4, 104:16 - 104:22. Ash also accumulates on the air preheater surfaces, restricting flue gas flow through the air preheaters and reducing the unit's output. Stevens Test., Tr. Vol. 2-A 59:7 - 60:22; July 15, 2005 Email (Pl. Ex. 45), at AM-0266037, 38; September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; Koppe Test., Tr. Vol. 3-A, 14:11-14:15, 17:5-17:11.

62. Ameren's documents specifically identified the switch to PRB coal as the reason for increased flyash pluggage and load reductions. Project Approval Package (Pl. Ex. 1), at AM-00072585 ("The switch to 100% PRB coals has caused flyash pluggage in the reheater and economizer. The pluggage in the existing staggered economizer has caused load reductions."); Rush Island Resurfacing Study (Pl. Ex. 20) at AM-00499388 ("changing fuels resulted in economizer performance problems…and maintenance problems…"); Bosch Dep., June 12, 2014, Tr. 38:25 – 39:7; *see also* July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters).

63. Mr. Koppe and Mr. Stevens explained that the boiler components were all suffering from the same underlying pluggage problem that collectively contributed to limiting air and gas flow through the boiler, thus reducing the amount of coal that could be burned. Stevens Test., Tr. Vol. 1-B, 108:13-109:13; Koppe Test., Tr. Vol. 3-A, 28:7-14, 29:2-8; see also Koppe Test., Tr. Vol. 4-A, at 46:23-47:18 (discussing the cumulative effect of the air preheaters,

reheater, and economizer pressure differentials on overall pressure drop throughout the boiler and its impact on the ID fans).

64. Jeff Shelton, an Ameren trial witness, similarly testified that because they all collectively contribute to the problem, the air preheaters, economizer, and reheater have to be looked at together when considering the effects of pluggage on the unit's ability to generate. Shelton Test., Tr. Vol. 10-A, 106:13-24.

65. Pluggage in the economizer with PRB ash was exacerbated by the original economizer's staggered alignment design, which created a torturous flow path for the flue gas and ash. Together with the switch to PRB coal, the economizers' staggered alignment also resulted in erosion, thinning, and tube leaks. Stevens Test., Tr. Vol. 2-A 30:19 - 32:14, 33:9-22, 40:11-19.

66. Ameren attempted to remedy the problems in the economizer through soot blowing and off-line cleanings, but these efforts did not solve the problem. Pluggage and erosion kept occurring, and the end of the economizers' lives were approaching. Stevens Test., Tr. Vol. 2-A 32:7-23.

67. The original design of the reheaters also exacerbated pluggage due to PRB coal. The spacing of the reheaters, along with the use of PRB coal, led to pluggage of the gas lanes through the reheaters. Contemporaneous documents indicated that "fouling is a daily concern," that pluggage occurred in certain areas of the reheater across the entire boiler width, and that shotguns and dynamite needed to be used to remove the pluggage. Stevens Test., Tr. Vol 2-A, 43:3-45:13; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735.

68. Ameren attempted to address the problems with the reheaters through cleanings, including soot blowing, and even dynamite. Strubberg Dep., Nov. 5, 2013, Tr. 162:7-19, 174:9-

23. However, because of end of life considerations, it became necessary to replace the reheaters. Stevens Test., Tr. Vol. 2-A, 44:22 – 45:13, 47:20-24.

69. The original air preheaters also consistently experienced pluggage. With the switch to PRB coal, ash accumulated on the air preheater surfaces and built up on itself. Ultimately, the pluggage also led to an end-of-life situation for the air preheaters. Stevens Test., Tr. Vol. 2-A 59:7 – 60:22. As an internal Ameren email stated, "It sounds like we have to live with the load limitations on RI due to fan capacity limits. Is there anything else we should look at, or as Jon suggests, is this beyond recovery due to the permanently plugged air heaters." July 15, 2005 Email (Pl. Ex. 45), at AM-0266037; Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (air preheater fouling was "permanent"); *see also* September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160 (noting continued air preheater fouling).

70. The specific mechanisms by which pluggage from PRB coal restricted air and gas flow and limited boiler operation were explained by Mr. Koppe. As noted previously, each boiler's FD fans push air in through the air preheaters where it is warmed up before it enters the furnace areas of the boiler. Koppe Test., Tr. Vol. 3-A 16:16-20. The very hot gases then flow up through all of the boiler tube components and back through the other side of the air preheaters, through the precipitator, and then are sucked out by ID fans, before going out the stack. Koppe Test., Tr. Vol. 3-A 16:20-17:2. When pluggage gets bad enough, it is no longer possible to push enough air into the furnace to burn as much coal as could otherwise be burned. That reduces the amount of coal that is burned, which reduces the amount of steam that is generated, which reduces the amount of electricity that is produced. Koppe Test., Tr. Vol. 3-A, 17:3-11.

71. Pluggage limited the amount of coal that could be burned in several ways. First, pluggage impacted the pressure differentials (also known as "delta P") across the air preheater and economizer, which limited air and gas flow and reduced the amount of coal that could be burned. As discussed above, the hot gases flow through the boiler as air is pushed into the boiler by FD fans and pulled by ID fans. The amount of air pushed into the furnace has to be in balance with the amount of gas that goes out of the furnace. As a component gets plugged, it takes more pressure to push the gas through it. The "delta P" represents the change in pressure from the inlet to the outlet of the various boiler components. When the pressure drop gets too high, the amount of gas flow out of the furnace must be reduced, which requires reducing the amount of air coming into the furnace, which reduces the amount of coal the boiler can burn. Koppe Test., Tr. Vol. 3-A, 17:12-18:21.

72. Second, pluggage also impacted the FD and ID fans. As pluggage got worse, the ID fans, which create a vacuum to suck air out of the boiler, had to work harder and harder to pull air, and eventually got to the point where they were "fan-limited" and could not suck any more without damaging equipment. Cardinale Dep., July 31, 2014, Tr. 103:17-205:17. So the ID fans had to reduce power, which also reduced the amount of coal that could be burned. Koppe Test., Tr. Vol. 3-A., 19:18-20:16.

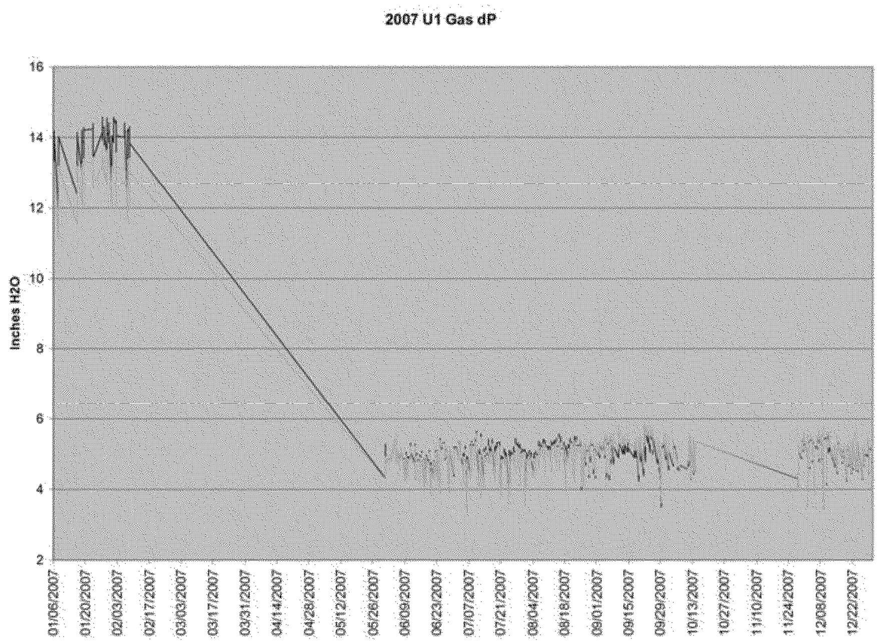
73. As the air preheaters plugged up more and more, the FD fans also had to work harder and harder to get air into the boiler. Bosch Dep., June 12, 2014, Tr. 38:25 – 40:11. Eventually the FD fans were maxed out and they could not push any more air, which limited the amount of coal that could be burned. Bosch Dep., June 12, 2014, Tr. 39:19 – 40:11. This typically happened in the summertime. Koppe Test., Tr. Vol. 3-A, at 20:17-21:11; Koppe Test., Tr. Vol. 4-A 44:13-23 ("on the rare occasions when I have before seen units limited by FD fans,

it is because the pluggage has gotten so severe in the summer months the FD fans use up all their margin and can't push any more air"); Birk Dep., Sept. 24, 2013, Tr. 194:7-16; *see also* July 2005 email, Pl. Ex. 45 (discussing "permanently plugged air heaters" and noting that the units "run out of FD fans when ambient temps come up in the summer months").

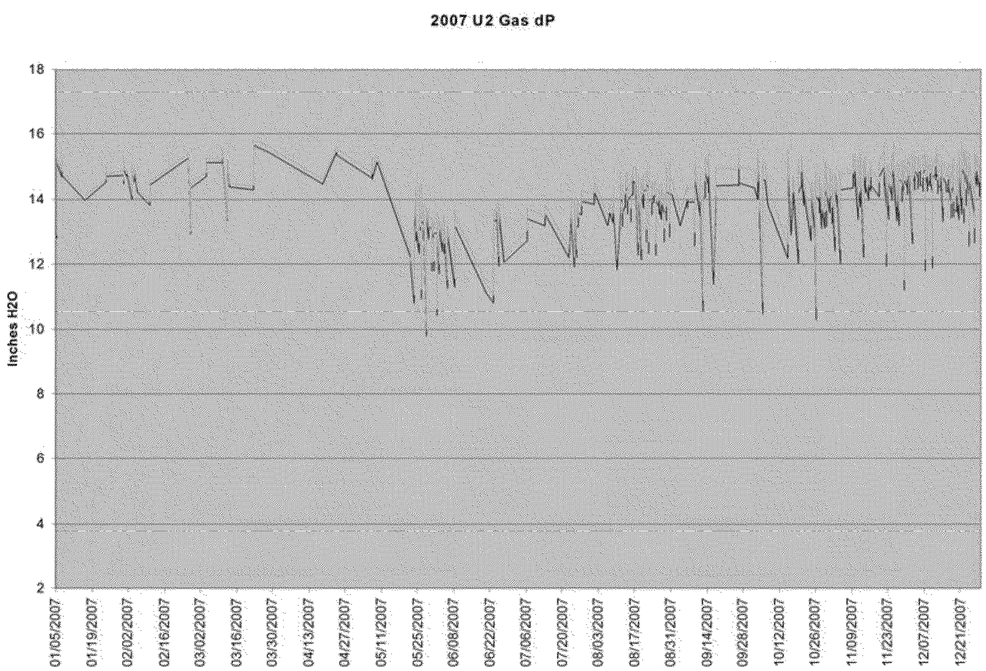
74. In the short term, Ameren coped with pluggage by shutting the units down periodically to conduct high-pressure washes to try to clean out some of the pluggage. Koppe Test., Tr. Vol. 3-A 22:3-12.; Stevens Test., Tr. Vol. 2-A, 59:7-22; Cardinale Dep., July 31, 2014, Tr. 41:15-43:10. This ameliorated the problem somewhat, but it did not solve it. Koppe Test., Tr. Vol. 3-A 22:3-12. The pressure drop would improve somewhat following a cleaning, but "much of the deposits in the air heater were so hard that they couldn't be removed even with a high-pressure wash." *Id.* at 25:12-21; Stevens Test., Tr. Vol. 2-A, 66:8-23; Cardinale Dep., July 31, 2014, Tr. 84:3-21.

75. Evidence of these problems was specifically discussed in company presentations to Ameren executives and memorialized in documents such as the 2008 "State of the System" report. 2008 State of the System (Pl. Ex. 15), AM-00196593, at AM-00196898-923; Meiners Test., Tr. Vol. 7-B, 58:20-59:8 (State of the System presentations were an opportunity to review the performance of plant equipment with Ameren executives). For instance, the 2008 State of the System report included a graphical representation of the high differential pressure problems caused by pluggage, showing very high differential pressure ranging from 12 to over 14 inches of water pressure at the beginning of 2007 at both Unit 1 and Unit 2. The two graphs are found in Pl. Ex. 15, at AM-00196909-10:

2007 U1 Gas dP



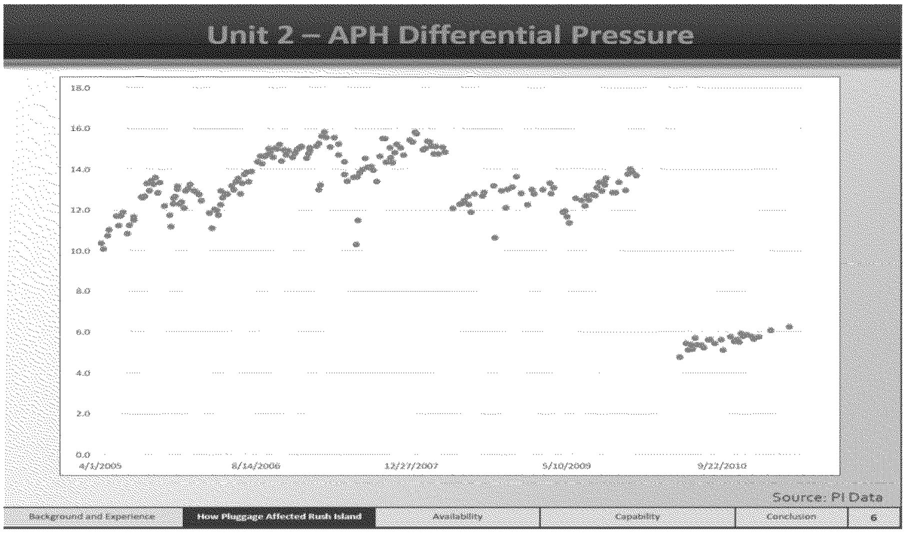
2007 U2 Gas dP



76. At Unit 1, the graphs indicate that differential pressure at Unit 1 dramatically dropped from about 14 inches of water pressure in early 2007 down to 4 to 6 inches of water pressure after the Unit 1 air preheaters were replaced in the Spring of 2007. Pl. Ex. 15, at AM-00196909. At Unit 2, the graph shows the permanence of the pluggage. As compared to the dramatic improvement achieved at Unit 1 due to the boiler component replacements, the Unit 2 graph shows only a very small improvement in differential pressure (from 14 down to 12 inches) following a washing of Unit 2 in the Spring of 2007, which almost immediately crept back up to 14 inches. Pl. Ex. 15, at AM-00196910. Koppe Test., Tr. Vol. 3-A, at 23:15 – 26:3.

77. The differential pressures described in the 2008 State of the System report before the boiler components were replaced were extremely high and caused load reductions. Koppe Test., Tr. Vol. 3-A, at 24:12-25:4. Ameren's trial witnesses Joseph Sind and Andrew Williamson referred to such differential pressures as "extremely high" and indicative of "high pluggage." Sind Test., Tr. Vol. 9-B, at 26:16 – 18 (air preheater differential pressures above even 11 inches are "extremely high"); Williamson Test. Tr. Vol. 9-B, at 44:4-11 (air heater differential pressure of 15 inches indicates "high pluggage").

78. Mr. Koppe's analysis of the company's operational data showed that the same high differential pressures reported in the 2008 State of the System report plagued Unit 2 throughout the years leading up to the 2010 major boiler outage. As Mr. Koppe's review of Ameren's data demonstrated, Unit 2's differential pressure at full load ranged between 10 and 16 inches of water in the years leading up to the projects, before dramatically improving following the 2010 major boiler outage. Koppe Test., Tr. Vol. 3-A 25:22-27:17 (discussing Koppe demonstrative 6).



79. Rush Island's operational data was also compiled in periodic full load tests, which Ameren generally performed on a weekly basis in order to determine the maximum output the unit could achieve at that time. Koppe Test., Tr. Vol. 3-B, 35:17-36:4. During full load tests, the unit tries to generate as much output as it can. Sind Test., Tr. Vol. 9-B, at 30:1-7; Williamson Test., Tr. Vol. 9-B, 42:11-20 (former Rush Island Superintendent of Operations testifying that he reviewed full load tests on a regular basis so he could understand what the capability of the units were); *see also* November 2007 email (Pl. Ex. 130), at AM-02635983 (Rush Island performance engineer James Bosch discussing full load test results after being asked to determine the "capacity" of Unit 1).

80. Plaintiff's Exhibit 928 is a compilation of these full load tests at Unit 2. In addition to reporting actual data such as pressure differentials, each full load test included a row for a possible narrative description of what was limiting load at the time. *See* Pl. Ex. 928, at Spreadsheet Cell B.2 ("Load Limited by"). In addition to the consistently high reported differential pressures, the full load tests performed during the PSD baseline period for Unit 2 (March 2005 to April 2007) are replete with examples where Ameren engineers went out of their

way to indicate in the narrative description of the load test reports that load was limited by the pluggage that is at issue in this case.[1]

81. Ameren also specifically quantified the generation losses due to the boiler components in company presentations. For instance, the 2008 State of the System presentation attributes 185,286 megawatt-hours of lost production at Unit 2 in 2007 to the air preheaters, as compared to only 15,197 megawatt-hours during that same year at Unit 1, which was the year the air preheaters were replaced at Unit 1. 2008 State of the System (Pl. Ex. 15), at AM-00196900.

82. Ameren trial witness David Strubberg conceded that the reported Unit 1 losses were smaller due to the replacement of the air preheaters. Strubberg Test., Tr. Vol. 8-A, 80:12-81:22 (discussing excerpt of presentation in Pl. Ex. 14). Similarly, a July 2006 email from Mr. Strubberg concerning the potential risks of postponing the Unit 1 major boiler outage estimated an approximately 35 MW load reduction due to pluggage. Strubberg Test., Tr. Vol. 8-A, 90:11-91:10.

83. The pluggage at Unit 2 continued to get worse in the years leading up to the 2010 major boiler outage. As ash plugged up the economizer or air preheater, some of it could be removed relatively easily. But a hard layer of ash deposit would form on the surfaces that could

---

[1] *See* Pl. Ex. 928, at Cell O.2 ("FD Fan Capacity"), W.2 ("ID FAN SUCT PS"), Y.2 ("ID Fan suction press"); AJ.2 ("ECON PLUGGAGE ID FAN SUCT). AK.2 ("Due to pluggage in boiler, it limits ID fan suction pressure"); AL.2 ("limited by the ID fan suction pressure…Boiler is plugged"); AO.2 ("ID suction Supht [sic] plugged Econ plugged"); AP.2 ("ID Fan Suction (Plugged Boiler)"); AQ.2 ("ID Fan Suction (Plugged Boiler)"), BD.2 ("02 blr pluggage"), BF.2 ("FD FANS"); BV.2 ("APH Pluggage"), BW.2 ("APH Pluggage"), BX.2 ("APH Pluggage"), BY.2 ("APH Pluggage"), BZ.2 ("ID Fan Suction Pressure"), CA.2 ("ID FAC SUCTION PRESS."), CC.2 ("ID Fan Suction"); CE.2 ("Blr Pluggage"), CH.2 ("APH Pluggage), CI.2 ("Suction Press."), CJ.2 ("APH Pluggage"), CK.2 ("APH Pluggage"), CN.2 ("ID Fan Suction Pressure"), CO.2 ("APH Pluggage"), CP.2 ("ID suc press Blr & APH's plugged"), CQ.2 ("APH Pluggage"), CR.2 ("ID FAN SUCT"), CS.2 ("APH Pluggage"), CT.2 ("Aph Pluggage"), CU.2 ("APH Pluggage"), CV.2 ("ID fan suction pressure").

not be removed "short of going in with a chisel and chiseling it out inch by inch. So as time went on, the thickness of these hard layers increased and that means that even after washing these components, the pressure drops were still very high." Koppe Test., Tr. Vol. 3-B, 20:1 – 21:7. This inability to remove the load limitations with high pressure washes was specifically identified in project justification documents for Unit 2. An Ameren memo reported: "A high pressure wash can restore some of the pressure loss, but the gains are dimensioning [sic] with an ever increasing accumulation of hardened fly ash." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160.

84. By 2008, pluggage of the Unit 2 air preheaters had gotten so bad that Ameren had to install a bypass as a temporary measure to allow gas to get around the pluggage. Koppe Test., Tr. Vol. 3-B, 21:8-21:19; Caudill Test., Tr. Vol. 10-B, 40:25-41:7; Cardinale Dep., July 31, 2014, Tr. 103:17-105:17 ("What they did on Unit 2, put in a pipe bypass around the air preheater because they really had serious pluggage problems."). The effect of the bypass would be to increase the electrical output of the unit and decrease its efficiency. Koppe Test., Tr. Vol. 3-B, 21:25 – 22:10; Cardinale Dep., July 31, 2014, Tr. 43:1-45:10 ("certainly bypassing the air preheater is not something you want to do"). Out of all the plants that Mr. Koppe has assessed throughout his career, he has never seen another example of such a bypass being installed. Koppe Test., Tr. Vol. 3-B, 21:20 – 21:24.

85. The effects of pluggage were also well-documented in other contemporaneous documents. Ameren described the pluggage at Unit 2 in a letter it sent to EPA's Clean Air Markets Division in 2008, "Unit 2 generation has been limited to approximately 90 percent of normal load since the middle of 2007 due to gas flow restrictions in the air preheater." April 7, 2008 Letter (Pl. Ex. 934), at AM-00015890-MDNR. When shown the document at trial, Ameren

capability expert witness Mr. Marcus Caudill referred to that amount as a "huge" load limitation. Caudill Test., Tr. Vol. 10-B, 39:19 – 41:14.

86. Similarly, in a December 16, 2009 email, which was written after the boiler work had been performed on Unit 1 but before it had been performed on Unit 2, Ameren employee Jeff Shelton wrote that the difference between the Unit 1 and Unit 2 capabilities grew bigger in the summer "due to draft limitations on Unit 2 and that following the boiler work this outage, we expect Unit 2 to not be as limited in the summer due to the draft issues." December 6, 2009 Email (Pl. Ex. 508), at AM-02248370; Shelton Test., Tr. Vol. 10-A, 93:21-94:18.

87. Mr. Shelton recognized that Unit 2 was draft limited in prior years as well. For instance, Mr. Shelton observed in 2008 that Unit 2 "ran into limitations due to gas path pluggage and air heater dps." December 18, 2008 Email (Pl. Ex. 542); at AM-02462552; Shelton Test., Tr. Vol. 10-A, 96:3-97:4.

88. In light of this evidence, Ameren's expert witness on the capability of the units, Marcus Caudill, agreed that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages. Caudill Test., Tr. Vol. 10-B 35:18-22.

4. Availability losses caused by the replaced components prior to the 2007 and 2010 outages as reported to the Generating Availability Data System

89. Ameren uses the Generating Availability Data System ("GADS") to collect and track operating data for the Rush Island plant, including event data and performance data. The event data tracks causes of lost generation such as derates and full outages, while performance data tracks statistics such as generation, fuel usage, and hours of operation. Anderson Test., Tr. Vol. 7-A, 5:22-6:14.

90. Plaintiff's expert Mr. Robert Koppe, who has been a power plant performance consultant since the 1970s, had a leading role in developing the GADS database, including writing the manual that all utilities use in deciding how to report their data. Koppe Test., Tr. Vol. 3-A 7:18 – 11:4. Mr. Koppe developed the original list of cause codes that all utilities use to report events in GADS. *Id.* at 10:17-11:4, 40:9-13.

91. Throughout his career, Mr. Koppe has been hired by dozens of utilities to analyze the performance of their generating units. Koppe Test., Tr. Vol. 3-A 11:5-20. He has analyzed performance issues relating to hundreds of generating units. *Id.* at 13:17-25.

92. GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Koppe Test., Tr. Vol. 3-A 10:5-11. GADS was developed so that utilities could improve the performance of their generating units. *Id.* at 10:12-16.

93. Whenever a unit has a problem that limits the amount of electricity it can generate, it is supposed to be reported as an "event" in the GADS data. That could be because the unit was operable but its maximum output was reduced (derated) or because the unit could not operate at all because it was in an outage. Koppe Test., Tr. Vol. 3-A 31:1-9.

94. A statistic known as equivalent availability takes account of the effects of such deratings and outages on the availability of the unit to operate. Koppe Test., Tr. Vol. 3-A at 30:1-19. A derating reflects times when the unit was not capable of operating at its maximum output due to an equipment problem. *Id.*

95. Staff at the Rush Island plant contemporaneously record event data that identifies the causes of lost availability. These event data are then further reviewed for accuracy on a

monthly basis before being uploaded into the company's GADS system. Anderson Test., Tr. Vol. 7-A, 15:9-18.

96. The Ameren performance engineer at the Rush Island plant who was responsible for ensuring the accuracy of the GADS event data was James Bosch. Anderson Test., Tr. Vol. 7-A 42:9-15; Koppe Test., Tr. Vol. 3-A 32:25 – 33:3; Meiners Test., Tr. Vol. 7-B, 38:13-24.

97. It is common for utilities to track the causes of their unavailability so that they can quantify the effects that each problem or component is having on availability. In order to improve availability, utilities need to know what the problems are. Koppe Test., Tr. Vol. 3-A at 31:17-24.

98. Ameren is no different. Unit availability, particularly at low-cost units like the Rush Island units, is very important to Ameren. The company tracks availability "quite closely" and awards salary bonuses under its "Key Performance Indicator" program to some employees based in part on meeting availability targets. Naslund Test., Tr. Vol. 6-B, 8:7-16; Response to Interrogatory No. 65 (ECF No. 823); Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 123:12-124:15; February 6, 2007 Email (Pl. Ex. 103), at AM-02272420.

99. The Key Performance Indicator bonuses are paid for by Ameren's customers. Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 124:16-125:9.

100. Improving unit availability was always a goal for Ameren. If a unit is experiencing forced outages, the company would like it to perform better. Naslund Test, Tr. Vol. 6-B, 11:17-24; 13:15-18. Mr. Naslund, vice president of power operations, told the 1500 Ameren employees under his supervision that perfect availability would be 100%. *Id.*; Generation Times Article (Pl. Ex. 930), at AM-02583221.

101. Staff at the Rush Island plant use GADS data to assess the status of the plant's equipment, and to adjust their predictions of future availability. Anderson Test., Tr. Vol. 7-A 59:25-60:6; Vasel Dep., Aug. 15, 2013, Tr. 83:22-25.

102. The availability targets set by the company are identified down to the tenth of a percentage point. The company also uses availability predictions to know how much coal to buy. Naslund Test., Tr. Vol 6-B, 10:20-11:9; *see also* February 6, 2007 Email (Pl. Ex. 103), at AM-02272420 (discussing proposal to adjust availability KPI bonus target by half a percentage point).

103. Ameren specifically used GADS data to analyze whether to do major capital projects. Koppe Test., Tr. Vol. 3-A at 31:25-34:3. Mr. Bosch, who did not testify at trial, reiterated the importance of such data to the capital project justification process in a 2002 email: "In order to place capital projects in the budget, they must be justified through the EVA program. EVA is a corporate justification software package which incorporates all the required components to derive a recommendation for project approval. ***The most compelling input in the justification calculation is lost generation. These lost generation figures are compiled and easily accessible in the NERC/GADS reporting program.***" June 25, 2002 Email (Pl. Ex. 99), at AM-02254509 (emphasis added); Bosch Dep., June 12, 2014, Tr. 73:11-74:8; Pope Dep., Sept. 20, 2013, Tr. 25:17-26:4 (management needed to know that there was an economic benefit before approving an investment).

104. Ameren's EVA Program, or Economic Value Added program, was used to compare two scenarios from a financial point of view in order to justify projects and look at the alternatives. Boll Dep. Tr., Dec. 12, 2013, 126:15-127:11; Generation EVA Instructions, (Pl. Ex. 331), at AM-00491836. The company's financial model for justifying projects based on their

availability impacts is capable of determining the effect on anticipated revenue of as little as a 0.1 percentage point change in expected availability. Meiners Test., Tr. Vol. 7-B, 44:23-45:1; June 15, 2009 CPOC Email (Pl. Ex. 895), at 02632840.

105. Ameren also uses GADS availability data to report the causes of lost generation at a plant to financial analysts on quarterly conference calls. Anderson Test., Tr. Vol. 7-A, 16:12 – 16:19.

106. In this case, Mr. Koppe looked at every single event reported in the GADS data for the 60 months prior to the project and determined which ones "would not have occurred but for the problems at issue in the components at issue in this case." Koppe Test., Tr. Vol. 3-A, 34:7-12. Mr. Koppe reviewed each GADS event and description as reported by Ameren for the relevant time period and then reviewed other sources of information to understand the cause of each event. Koppe Test., Tr. Vol. 3-A, 38:18-39:3.

107. Mr. Koppe specifically included the GADS data for the PSD baseline period for Unit 1 that has been used by Ameren in this litigation (February 2005 to January 2007). During that baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year, which is equivalent to roughly 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id.* These losses were widespread and covered a large fraction of all the months in the baseline. Koppe Test., Tr. Vol. 3-A, 46:25-47:6.

108. Mr. Koppe also specifically reviewed the GADS data for the PSD baseline period for Unit 2 used by Ameren in this litigation (April 2005 to March 2007). During the baseline

period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:13.

109. The deratings experienced at Units 1 and 2 were not short-term or one-time events. For instance, Unit 1 was continuously derated for the entire months of June, July, August, September, and October 2006, meaning that the unit was continuously derated every single day of each of those months. Unit 2 similarly experienced continuous derates. Anderson Test., Tr. Vol. 7-A, 50:21-52:16.

110. Mr. Koppe's compilation of derates included certain GADS events identified as "FD fan capacity" limitations because the units would not have been limited by FD fan capacity had it not been for pluggage in the air preheater. Koppe Test., Tr. Vol. 4-A, at 60:9-61:3; *see also* Koppe Test., Tr. Vol; 3-A, 96:19-97:18.

111. Rush Island Plant staff similarly attributed such fan capacity problems to the boiler components at issue. For instance, a spreadsheet attached to an April 30, 2006 email from Robert Meiners indicates that plant staff determined that Units 1 and 2 were experiencing load limitations during the summer of 2005 that would be eliminated once the reheaters, economizers, and air preheaters were replaced. *See* April 30, 2006 Email and Attached Condition Assessment (Pl. Ex. 106), at Rush Island Spreadsheet Tab, Line 63 (noting that "FD Fans" at Unit 1 and Unit 2 "[c]urrently limit load during summer, but should be eliminated with boiler pressure part and APH"); Anderson Test., Tr. Vol. 7-A, 49:8-25.

112. As described by Ameren's engineers at the time, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units. July 15, 2005 Email (Pl. Ex. 45) at AM-0266037 (also noting that the "Unit 2 Air Pre-heater delta P's [were] running at 12 inches at full load" and that the "baskets will have to be replaced on the APH's to make an impact on FD fans"); July 21, 2004 Email (Pl. Ex. 555), at AM-02485899; *see also* FOF 80 & n.2 (summarizing descriptions in weekly full load tests). The limitation on the unit's ability to operate was estimated to cost Ameren approximately $25,000 per day. July 15, 2005 Email (Pl. Ex. 45), at AM-02666038.

5. Reduction in the maximum capability of Unit 2 prior to the 2010 outage

113. In addition to lost availability due to outages and derates as reported in GADS, the switch to PRB coal also resulted in a significant reduction in the reported maximum hourly capability of the units prior to the major boiler outages. Koppe Test., Tr. Vol. 3-A 90:11-91:4, Vol. 4-A, 33:10-34:2.

114. The capability of a unit is the maximum electric output that it can produce at that time if asked to do so. Koppe Test., Tr. Vol. 3-A, 84:14-23. The terms "capability" and "capacity" are often used interchangeably. *Id.* at 85:25-86:5

115. Ameren issued annual capability tables, which "represent the expected average output of each unit based on typical ambient conditions." *See, e.g.*, 2011 Capability Table (Pl. Ex. 257), at AM-00067232. The reported capability of a unit is an estimate of what the utility expects the capability of the unit to be in the following year. Koppe Test., Tr. Vol. 3-A, 84:23-85:2. The magnitude of a reported derating is affected by the reported capability. *Id.* 85:3-10; *see* December 2010 Capability Table (Pl. Ex. 257), at AM-00067232.

116. Gross capability or gross electrical output is the amount of electricity that the generator produces. Net capability or net electrical output is the amount of electricity that goes out to the grid. The difference between net and gross capability is the electricity the plant itself uses to operate, otherwise referred to as auxiliary load. Koppe Test., Tr. Vol. 3-A, 85:11-17; Koppe Test., Tr. Vol. 3-B, 11:6-15; Shelton Test., Tr. Vol. 10-A, 84:10-15.

117. A reduction in auxiliary load is an improvement in net efficiency, but it does not affect the amount of coal that the unit is capable of burning. It just means that less power is used to run the plant and more power is sent to the grid. Generator output is the same, heat input is the same, but more megawatts can be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10.

118. Ameren lowered the reported capability of Unit 2 substantially from 2005 to 2006. The reduction was about 10 megawatts in the winter and 20 megawatts in the summer. Unit 2's reported capability remained essentially the same until 2010 and then increased substantially in 2010 and 2011. Koppe Test., Tr. Vol. 3-A, 88:13-23.

119. The reduction in reported capability was the result of the effects of pluggage. Koppe Test., Tr. Vol. 3-A, 90:11-91:4. In 2005, pluggage caused Unit 2 to frequently not be able to meet its reported capability. Koppe Test., Tr. Vol. 4-A, 33:10-34:2. Similarly, Unit 2 was unable to meet its reported capability in the summer of 2005 due to FD fan capacity limitations. January 4, 2006 Email (Pl. Ex. 157), at AM-027432293; Koppe Test., Tr. Vol. 3-A, 91:9-95:11. The reason the fans were running out of capacity in the summer was because of pluggage in the boiler, specifically pluggage in the air preheater. Koppe Test., Tr. Vol. 3-A, 96:19-97:18. As Ameren documents describe it, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units.

July 15, 2005 Email (Pl. Ex. 45), at AM-02666037. Such problems with summer capacity were also identified in the project justification documents for Unit 2, where Ameren reiterated that "the current air preheater baskets have continued to foul to the extent that fans are load limited particularly in the summer months." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; *see also* Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (noting that air preheater fouling was "permanent").

120. The capability of Unit 2 prior to the 2010 major boiler outage was also measured in Ameren's weekly full load tests. The average capability of Rush Island Unit 2 as measured by Ameren in all of the full load tests that were conducted during the PSD baseline period (March 2005 to April 2007) was only 620 gross megawatts. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; *see* Pl. Ex. 928 (Rule 1006 summary of full load tests for Unit 2).

121. In the years leading up to the 2010 major boiler outage at Unit 2, Ameren further quantified the megawatt capability loss that was due to the boiler components at issue. In Ameren's 2008 annual "State of the System" presentation in 2008, it assigned "25-30 MW" to the Unit 2 "BLR/AHS replacement" in addition to another 13 megawatts that could be gained from replacing the low pressure turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628.

122. Ameren assigned 22.5 megawatts to the reheater, economizer, and air preheater in a financial analysis for the 2010 major boiler outage. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Vol. 3-B, 30:4-32:23. The 22.5 megawatt value was a weighted average based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more megawatts of capacity during the three summer months and 20 more megawatts for the remainder of the year. Koppe Test., Tr. Vol. 3-

B, at 27:7-32:23; see Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30 MW gain in summer (3 mos), 20 MW gain balance of year from Reheater, Economizer and APH investment").

123. Ameren's final work order authorizations for the reheater, economizer, and air preheater, completed in the fall of 2009, similarly described that the "combined" effect of these component replacements would result in a "gain of 30 MW in the summer and 20 MW in the winter" at Unit 2. October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; *see* September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (same language in air preheater justification that "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements").

124. Ameren witness David Boll testified in his deposition that these predicted additional megawatts represented "regained capacity" that had been lost due to the inability to pull gas flow through the plugged air preheaters. Boll Test., Tr. Vol. 8-B, 51:23-52:4, 54:21-25.

125. A summary of the anticipated benefits of the work written in 2010 similarly referred to the fact that "[a]pproximately 30 Megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters." March 31, 2010 Email re Newsletter (Pl. Ex. 893), at AM-02229417.

C. The Approval and Engineering Process for the 2007 and 2010 Major Modifications

126. The formal approval and engineering process for the 2007 and 2010 major boiler projects began at least three years prior to the first outage. The replacement of all four components was considered together for planning purposes, beginning as early as 2004. For instance, by December 2004, Ameren had created a preliminary budget for replacement of the Unit 1 economizer, reheater, lower slope tubes, and air preheaters, at an estimated capital cost of

more than $25 million. Stevens Test., Tr. Vol. 2-A 5:2-7; December 20, 2004 Generating Engineering Budget Project Proposal (Pl. Ex. 323); RFA 393.

127. A 500-page Project Book for Unit 1 was compiled as a reference for the work to be completed during the Unit 1 outage. The replacement of the economizer, reheater, lower slope tubes and air preheaters were coordinated by Alstom Power and generally treated together within the Project Book. Rush Island Unit 1 Project Book (Pl. Ex. 63), at AUE-00156352 (collectively referring to "Reheater, Economizer, Lower Slope, Air Heater Rotor Replacements" as a single major project); *id.* at 365 (same), 519 (same), 539 (same); Stevens Test., Tr. Vol. 2-A. 17:1- 18:10.

128. The documentation in the Project Book also confirmed that one purchase order for engineering, materials, and construction services was issued to Alstom Power as early as 2005, which included the replacement of the economizer, reheater, lower slope tubes, and air preheaters. Pl. Ex. 63, at AUE-00156395-398.

129. The replacements of the economizers, reheaters, lower slopes, and air preheaters were all approved under Ameren's Work Order Procedures. Stevens Test., Tr. Vol. 1-B 72:15-21, 91:19 – 92:3.

130. While the air preheaters were also subject to their own work order justification process, the air preheater justification documents specifically combined the air preheater replacements with the reheater, economizer, and lower slopes as part of a "major refurbishment" at both Unit 1 and Unit 2. October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

131. Similarly, prior to replacing the Unit 2 air preheaters, Ameren reiterated its reliance on the "combined" effect of the air preheaters, reheater, and economizer for purposes of

justifying the replacements. September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323 (same); *see also id.* at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater.").

132. Ameren's documents also indicate that the replacement of all the components was combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacements as "part of a Major Mechanical Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." Project Approval Package (Pl. Ex. 1), at AM-00072590; Project Approval Package (Pl. Ex. 4), at AM-00072859; Stevens Test., Tr. Vol. 2-A 10:19-11:18, 13:23-14:7.

133. The engineering specification issued by Ameren called for bids from outside engineering firms for the design, fabrication, and installation of the boiler components at Rush Island Units 1 and 2. Ameren consolidated the replacement of the economizer, reheater, lower slope tubes, and air preheaters for purposes of issuing the specifications. Specification No. EC-5491 (Pl. Ex. 10); Stevens Test., Tr. Vol. 2A 15:19 - 16:13.

134. Ameren provided specific design requirements for the replacement components, including a number of significant design changes that were intended to upgrade and improve the performance of the boiler as a whole. Stevens Test., Tr. Vol. 2-A, 32:24-33:22, 34:8-12, 45:14-46:25, 55:9-56:4, 66:5-67:9; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (noting combined project objectives of redesigned economizer and air preheater).

135. In contrast with routine work undertaken at utility plants, the replacement of the economizers, reheaters, lower slopes, and air preheaters required approvals of executives at the highest level of the company, including Ameren's CEO. The approval process required at least

10 layers of approval review. Stevens Test., Tr. Vol. 2-A 7:5-15, 13:15-22; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Form (Pl. Ex. 2), at AM-00072829; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

136. In August of 2005, Gary Rainwater, then the Ameren CEO, authorized the expenditure of $23,148,000 to replace the economizer, reheater, and lower slope panels at Rush Island Unit 1. Stevens Test., Tr. Vol. 2-A 7:5-15; Project Approval Package (Pl. Ex. 1), at AM-00072580. Mr. Rainwater also authorized the expenditure of $24,988,000 for the same work at Unit 2. Project Approval Form (Pl. Ex. 2), at AM-00072829. Earlier in the spring of 2005, Ameren Missouri Chief Operating Officer Thomas R. Voss authorized the expenditure of approximately $6.9 million for the design, fabrication, and installation of new air preheaters at Unit 1, and, in October of 2005, authorized approximately $7.5 million for similar work at Unit 2. Stevens Test., Tr. Vol. 2-A 13:15-22; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

137. After the 2007 major boiler outage at Unit 1, Unit 2 went through a second justification process in 2009. The Unit 2 major boiler outage had to be approved by an additional committee known as the Capital Project Oversight Committee ("CPOC"), Ameren's CEO Warner Baxter, and the full Board of Directors. Meiners Test., Tr. Vol. 7-B, 45:8-25, 46:6-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756. On August 14, 2009, Mr. Baxter reported that the outage had been approved. August 14, 2009 Email (Pl. Ex. 553), at AM-02480812.

D. Ameren Justified Replacing the Economizers, Reheaters, Lower Slopes, and Air Preheaters Because They Would Improve Operations and Allow the Units to Generate More

138. Ameren's contemporaneous project authorization documents identified the new economizers, reheaters, lower slopes, and air preheaters as components that were "improved" and "redesigned" in order to fix the operational problems that had been caused by burning PRB coal and age-related deterioration. Stevens Test., Tr. Vol. 2-A, 8:21- 9:6; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Package (Pl. Ex. 3), at AM-00072831; Boll. Dep. Tr., Dec. 12, 2013, 164:24-165:26, 168:19-169:6; Birk Dep., Sept. 24, 2013, Tr. 194:1-16; Meiners Dep., April 8, 2014, Tr. 237:18-238:11; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

139. Ameren described the planned "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater – redesigned for PRB coal
> - Economizer – redesigned for PRB coal
> - Lower Slope – ruggedized design to better withstand slag falls
> - Air Preheater – redesigned for ease of future basket replacement.

Project Approval Package (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

140. Ameren's expert Jerry Golden agreed that the components replaced at Rush Island were redesigned. Golden Test., Tr. Vol. 8-A, 10:6-10; see also RFA Nos. 377 to 383, 386-387, 389-390, 395-401, 407. Further descriptions of these redesigns are provided below.

141. *Economizer Redesign*: The design of the new economizers was substantially different from the original design. The redesigned economizers were in-line, rather than the original staggered design, which allowed gas to flow through the boiler more easily. The new economizer design made the economizers less subject to fouling and pluggage. Stevens Test., Tr. Vol. 2-A 32:24 – 33:22; 34:8-12; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080325-329; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966728-730.

142. *Reheater Redesign*: The design for the new preheaters was significantly different from the original design. Stevens Test., Tr. Vol., 2-A 45:14 - 18; Boll Dep. Tr., Sept. 5, 2014, 68:11-70. The spacing between the tubes was increased from 10 to 15 inch centers, and the number of front assemblies was reduced from 72 to 48. The bottom of the reheaters was changed from a sloped bottom that closely tracked the boilers' nose to a horizontal bottom. The number of rear assemblies was decreased from 145 to 96 assemblies, and their height was increased. Similar to the design change for the front assemblies, the spacing between each tube was increased. Additionally, both the front and rear assemblies were platenized. Together, these changes allowed more space for gas and ash to flow through the reheaters without plugging or fouling. Stevens Test., Tr. Vol. 2-A 45:14 - 46:25; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080329-332; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966737-738.

143. *Lower Slopes Redesign*: The design for the new lower slope tubes at Unit 1 was a different design than the original lower slope tubes. Specifically, the new lower slope tubes had a thicker wall to prevent tube leak problems caused by slag falls. The space between each tube was decreased, adding greater strength to assist in slag fall protection. Additionally, the structural support was replaced to provide additional strength. Together, these changes made

the lower slope tubes stiffer, more rigid, and less likely to be crushed so easily. Stevens Test., Tr. Vol. 2-A 55:9 - 56:4; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080332-334; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966748-749.

144. *Air Preheaters Redesign*: The new, redesigned air preheaters were changed from the original three-layer Ljungstrom regenerative basket design to a two-layer design. The new two-layer air preheaters had a hot end layer and a cold end layer. In each air preheater, each layer had 24 baskets, each of which was 29 inches deep. While the original air preheaters each had 456 baskets, the new air preheaters had only 48 baskets total. The design was changed in order to minimize the outage time required for cleaning the baskets in the future. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21, 66:5 - 67:9; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080279, 348-353; RFA Nos. 331, 334.

145. Ameren specifically justified performing these boiler upgrades because they were expected to reduce forced outages due to tube leaks, eliminate load reductions, and increase the capability and availability of the units to operate. One of the specific expectations identified in the project justifications was that the replacements would eliminate outage time due to the components for the next 20 years. Stevens Test., Tr. Vol. 2-A 7:16-8:20, 25:12 – 26:11, 27:13-23, 59:7-60:22; 63:22-65:7; Golden Test., Tr. Vol. 8-A 12:14 – 13:8.

146. These expected improvements were explicitly stated in Ameren's project justification documents. For instance, after describing the "new, improved, redesigned" economizer, reheater, and lower slopes, **Ameren's project authorization for Unit 1 stated that "as a result" of the replacements, "Rush Island will eliminate forced outages due to reheater tube leaks for 20 years, eliminate 30 to 50 MW load reductions due to flyash pluggage of the current economizer, and reduce the number of tube leaks caused by slag**

falling on the furnace lower slopes." Project Approval Package (Pl. Ex. 1), at AM-00072580 (emphasis added); *see also* Project Approval Package (Pl. Ex. 4), at AM-00072858 (noting expected improvement in pressure drop across the air preheater, and two week reduction in future outage costs due to quicker basket replacements); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (project objectives include avoiding "load reductions" and "minimizing future forced boiler outages for the next 20 years"); September 18, 2009 Memo (Pl. Ex. 26), at AM-0954160 (noting that air preheater replacement "will reduce the gas side pressure loss across the air preheaters from 14 to 5 inches" of water pressure, and that project would result in a megawatt "gain").

147. Ameren expected that the work would reduce the number of forced outages due to these components "to zero." Project Approval Package (Pl. Ex. 1), at AM-00072585-586 ("Flyash pluggage of the economizer will be eliminated or greatly reduced due to the in-line spiral fin economizer… Forced outages due to tube leaks in the reheater and economizer will be reduced to zero."); *see also id.* at 590 ("completing this project will eliminate all the problems"); Project Approval Form (Pl. Ex. 2), at AM-00072829 (same statements for Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831-833, 837 (same statements for Unit 2); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966731, 740, 750 (identifying avoided costs associated with avoiding derates and outages due to boiler tube leaks); *see also* Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24.

148. Ameren ultimately decided not to replace the lower slopes at Unit 2 during the 2010 major boiler outage and therefore adjusted the overall availability improvement expected from the work downwards by 0.1% from 4.3% to 4.2%. June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632840; Meiners Test., Tr. Vol. 7B, 34:9-35:25.

149. Further evidence of Ameren's expectation of availability improvements is found in Plaintiff's Exhibit 126, which was a presentation that Mr. Meiners made to senior executives at a business plan meeting. Meiners Test., Tr. Vol. 7-B, 27:21-24, 28:18-20. One of the purposes of the presentation was to discuss component replacements and the condition of the reheater, economizer, air preheater, and lower slopes. *Id.* 28:10-17. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's availability would increase by almost 5%, from about 90% in 2005-2006 to 95% in the first year after both major boiler outages had been completed. *Id.* 31:15-21

150. Ameren's experts agreed that the expressed purpose of the work at each unit was the same: to improve capability and eliminate deratings. For instance, Mr. Golden confirmed that the work at both units was intended to eliminate pluggage and fouling of the economizers and reheaters, to eliminate future forced and maintenance outages caused by tube leaks, and to eliminate pluggage problems and deratings from the air preheaters. Golden Test., Tr. Vol. 8-A, 10:11-21, 13:16 – 13:21.

151. Mr. Golden also agreed that the purpose of replacing the lower slopes at Unit 1 was to eliminate tube leaks in the lower slope and damage resulting from slag falls and erosion following the switch to PRB coal. Golden Test., Tr. Vol. 8-A, 10:22-25.

152. Ameren's expert Mr. Caudill conceded that the expected benefits of replacing the components included reducing forced outages and eliminating or greatly reducing flyash pluggage at the units. As Mr. Caudill put it, "[b]asically that's what Ameren expected" based on a review of Ameren's project justifications. Caudill Test., Tr. Vol. 10-B, 36:10-37:2, 37:17-38:10.

153. Mr. Caudill also agreed that pluggage in the reheater, economizer, and air preheaters contributed to high differential pressure, which Ameren expected to reduce as a result of replacing the reheater, economizer, and air preheaters. Caudill Test., Tr. Vol. 10-B, 34:17-35:1, 35:14-17. In addition to eliminating load reductions, such improvements in differential pressure can result in some increase in net efficiency, but not gross efficiency. Caudill Test., Tr., Vol. 10-B, 35:11-13; Koppe Test., Tr. Vol. 3-B, 11:16-12:4, 28:18-29:4. Mr. Caudill conceded that Ameren did not justify the replacement of the economizers, reheaters, and air preheaters based on any expectation that they would result in an improvement in gross unit efficiency. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12.

154. Mr. Caudill also conceded that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages and that eliminating pluggage that is causing derates will allow a unit to generate at a higher gross load. Caudill Test., Tr. Vol. 10-B, 35:18-22, 37:3-16.

155. Ameren's final, updated justification for the 2010 major boiler outage reflected the company's expectation that the replacements would enable the unit to operate more and to produce more megawatts when operating. The justification identified two types of performance improvements from the boiler work: a capacity increase and an equivalent availability improvement. As described in a 2009 work order authorization request:

> A gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer and air preheater replacements. …. Also included in the justification is an approximate 3-4% improvement in equivalent availability of the unit.
>
> **Assumptions**: It is assumed that these boiler modifications will result in an improved operation of the unit that is at least equal to, if not better, than that currently experienced with Unit 1 which had similar modifications in 2007. This includes fewer load restrictions, improved equivalent availability and elimination of potential catastrophic failure of the economizer.

October 15, 2009 Memo (Pl. Ex. 23), AM-00926323; *see also id.* at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater."); Stevens Test., Tr. Vol. 2-A, 25:12- 26:11; 27:3-23.

156. The justification of additional generation from the replacements is also found in the financial analysis tool that was used to justify the 2010 outage. The availability gain used in the final financial analysis was the equivalent of "15 days of generation." Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48); Meiners Test., Tr. Vol. 7-B, 18:6-11, 18:21-19:16.

157. Ameren's final financial evaluation separately included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Tr. Vol. 3-B, 30:4-32:23. This capacity increase was based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more MW of capacity during the three summer months and 20 MW for the remainder of the year. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment").

158. The 22.5 MW increase in capacity was separate from the availability input used in the model. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing megawatt capability "gain" from boiler upgrade separately from 4.2% equivalent availability impact); Koppe Test., Tr. Vol. 3-B 30:8-31:7. It represented an increase over the capability that

Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, 28:2-12. The financial impact included significant "incremental power sales" that were calculated to have a favorable impact on ratepayers, shareholders, and earnings. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465691.

159. These boiler capacity and availability gains were also identified separately from an additional 15 megawatt capability gain from replacing the LP turbine with a more efficient design. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing gains separately in project economic analysis).

160. During the final 2009 approval process for the Unit 2 outage, Mr. Meiners reiterated the accuracy of these forecasts to Ameren's CEO, Mr. Baxter. May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits."); Meiners Test., Tr. Vol. 7-B, at 46:9-47:11.

E. Implementation of the 2007 and 2010 Major Modifications

161. Ameren installed the new economizer, reheater, two air preheaters, and lower slope panels at Rush Island Unit 1 during an outage that began on February 17, 2007 and ended on May 28, 2007. 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210.

162. On January 24, 2007, almost one month before the Unit 1 major boiler outage was to start, there were already 54 contractors on site. The previous week, 17 truckloads of tubing arrived on site and a crane was being constructed for use in replacing the reheater. Rush Island Project Book (Pl. Ex. 63), at AUE-00156343; Overhead Photo of Laydown Areas (Pl. Ex. 414), AM-00222751. This level of activity on-site, a month before the work had even started, is not typical of routine maintenance at a power plant. Stevens Test., Tr. Vol. 2-A, 18:14-19:19.

163. Ameren installed the new economizer, reheater, and two air preheaters at Rush Island Unit 2 during an outage that began on January 1, 2010 and ended on April 6, 2010. Vol. 2A, Stevens Test., 24:9-15; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

164. The replacements took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080233; Rush Island Project Book (Pl. Ex. 63), at AUE-00156362. Ameren's expert, Jerry Golden, acknowledged at trial that these replacements were not *de minimis* activities. Golden Test., Tr. Vol. 8-A, 33:9-18.

165. The size and extent of the components replaced during the 2007 and 2010 major boiler outages was massive, with the economizers, reheaters, and air preheaters each weighing hundreds of thousands of pounds. Stevens Test., Tr. Vol. 2-A, 13:10-14, 34:22-35:7, 50:11-13, 59:3-6, 67:21-68:5. For example, the new reheaters included two outlet headers that weighed 36,000 pounds each and 144 reheater tube assemblies, including 48 front pendant assemblies that were each approximately 49 feet tall and 96 rear pendant assemblies that were each approximately 35 feet tall. Stevens Test., Tr. Vol 2-A, 45:14-46:25, 50:10-13; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080330-332; RFA Nos. 386-387, 390, 395-398. If the Rush Island economizer's tubing was laid from end-to-end, the length of tubing would stretch around 140 miles. Stevens Test. Tr. Vol. 1-B, 79:20 – 80:5.

166. Given the complexity of the replacements, the components needed to be designed, engineered, and constructed by outside contractors, such as Alstom Power - the original manufacturer of the boilers, and numerous other contractors. The work involved was substantial, requiring hundreds of thousands of man-hours, and was well beyond the capacity of Ameren's

own staff. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252259, 260; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739979.

167. Heavy machinery was required to facilitate the removal of old components and installation of new, redesigned components. Multiple monorails were installed in order to maneuver the components. Stevens Test., Tr. Vol. 2-A, 18:24-19:11; 36:6-18; 38:11-19. Multiple large cranes were constructed to remove and lower the old assemblies to the ground and lift the new assemblies to the necessary height within the boiler. Each outage required the construction of two Manitowoc 888 cranes, as well as several other cranes, including Manitowoc 222 and 2250 cranes. Stevens Test., Tr. Vol. 2-A, 18:14-19:19; 48:12-20; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973. The largest Manitowoc crane had to be tall enough to remove 50-foot reheater assemblies through the roof at an approximately 270 foot elevation. Stevens Test., Tr. Vol. 2-A, 48:4 -15.

168. The process of removing each old component and installing each new component was highly complex. For the boiler components, each original assembly was cut out and removed one-by-one. Stevens Test., Tr. Vol 2-A, 36:11-19. Cuts had to be made in the side of the boiler lagging and walls at various elevations, including one at around a 200 foot elevation, as well as in the roof of the boiler house. Stevens Test., Tr. Vol. 2-A, 38:11-19, 47:25- 48:3. It would take months to facilitate the removal and re-installation. Stevens Test., Tr. Vol. 2-A, 38:25 – 39:9; 49:2 – 7. Many craftsmen were involved in the cutting and welding process. Stevens Test., Tr. Vol. 2-A, 50:20-51:1.

169. The 2007 major boiler outage at Rush Island Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. Ninety-one percent of the work done during the Unit 1 major boiler

outage was performed by contractors. While other work was performed, the replacement of the economizer, reheater, air preheaters, and lower slope panels was the most significant and costly work performed during the outage. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225259, 260.

170. The 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. 2010 Post Outage Report (Pl. Ex. 46), at AM-02739976.

171. The 2007 and 2010 major boiler outages were significantly different than typical power plant maintenance, repair, and replacement activities undertaken on a day-to-day basis. Ameren itself did not characterize the replacement of major components such as the reheaters, economizers, air preheaters, and lower slopes at issue in this case as "routine." Instead, Ameren described the work as "major boiler modifications" and identified the work as not recurring and not routine in its project documents. Stevens Test., Tr. Vol. 1-B, 65:24- 66:10, 66:8-71:2; Vol. 2-A, 9:24- 10:18, 11:19-12:2; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Project Approval Package (Pl. Ex. 1), at AM-00072591; Project Approval Package (Pl. Ex. 3), at AM-00072838; RFA No. 460.

172. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2. After the 2007 major boiler outage, Ameren's Vice President Mark Birk referred to the outage as the "most significant outage in Rush Island history." May 29, 2007 Email (Pl. Ex. 31). Mr. Birk specifically called out the replacement of several components – including the economizer, reheater, lower slope, and air preheaters – as distinct from "the routine maintenance that had to be performed" during the outage. *Id.* The 2010 major boiler

outage was similarly referred to as "among the most significant in [company] history." Jerry Odehnal Report (Pl. Ex. 40); *see* Vasel Dep., Aug. 15, 2013, Tr. 272:2-23 (describing exhibit 40); see also 2010 State of the System presentation , Pl. Ex. 41, at AM-02493747 (distinguishing the air preheater, reheater and economizer replacements from the "routine maintenance" done during the 2010 outage).

173. By the time of their replacements in 2007 and 2010, the reheaters, economizers, and air preheaters were more than 30 years old, nearing the end of their expected lives. These components had never before been replaced at Rush Island Units 1 and 2. Stevens Test. Tr. Vol. 1-B, 50:24-51:4, 81:19-82:1, 84:9-13; 108:13-109:3; Tr. Vol. 2-A, 9:24-10:18, 43:3-25; Golden Test., Tr. Vol. 8-A, 16:7-16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:6; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912 ("units have operated for nearly 30 years without replacing any of the major components"); Unit 2 ELT Progress Report (Pl. Ex. 110), at AM-02465689 ("The MBO [major boiler outage] is being undertaken to change out 2 major boiler components and the APH that are end of life…"); Unit 2 ELT Progress Report (Pl. Ex. 456), at AM-00953927.

174. Projects such as the economizer, reheater, air preheater, and lower slope replacements are not performed frequently during the life of a typical utility unit. Stevens Test., Tr. Vol. 1-B, 91:11-18. Ameren's expert Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of a lower slope is about 40 years. Golden Test. Tr. Vol. 8-A, 18:2-11. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. Golden Test., Tr. Vol. Vol. 8-A, 19:9-15.

175. Even looking exclusively to how common work is performed across the utility industry, Mr. Golden was able to identify few, if any, projects that rival the 2007 and 2010 major boiler outages at other Ameren plants or elsewhere in the utility industry. Mr. Golden has worked on 14 NSR cases since 2000 on behalf of electric utilities. Golden Test., Tr. Vol. 8-A, 6:3-16. During that time, he has collected a list of 18,300 projects undertaken at coal-fired power plants that he says are both capital projects and cost more than $100,000. Golden Test., Tr. Vol. 8-A, 25:11-14; 25:24-26:2, 26:13-16. However, Mr. Golden was not able to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. Golden Test., Tr. Vol. 8-A, 19:3-8; *see also* Vasel Dep., Aug. 15, 2013, Tr. 154:11-24 (unable to recall any other outage at Ameren when all components were replaced).

176. Similarly, even for the relatively few air preheater replacements that Mr. Golden did identify (35 out of approximately 1,200 coal-fired generating units operating in 2007), Mr. Golden was unable to testify that all were complete replacements or were comparable to those at Rush Island. Golden Test., Tr. Vol. 8-A, 20:2-23, 28:3-12, 28:17-29:5.

F. The Cost of the 2007 and 2010 Major Modifications

177. Replacement of the reheater, economizer, air preheaters, and lower slope at Rush Island Unit 1 ultimately cost approximately $34 million. Stevens Test. Tr. Vol 2A, 22:24-23:3; Golden Test., Tr. Vol. 8-A, 23:7-10.

178. Replacement of the reheater, economizer, and air preheaters at Rush Island Unit 2 ultimately cost more than $38 million. Stevens Test., Tr. Vol 2-A, 28:5-9; Golden Test., Tr. Vol. 8A, 23:7-10.

179. Ameren's budget for the Rush Island plant is divided into an Operation and Maintenance ("O&M") component and a Capital component. Stevens Test., Tr. Vol. 1-B, 89:23-90:3.

180. A capital project is one that would improve the value of the asset. Stevens Test., Tr. Vol. 1-B, 91:1-10.

181. The component replacements at issue in this case were capital projects. The projects were actually funded out of Ameren's capital budget rather than its O&M budget. Stevens Test., Tr. Vol. 1-B, 89:23-90:3, Vol. 2-A 5:12-17; Golden Test., Tr. Vol. 8-A, 23:14-15.

182. Costing $34 to $38 million, the boiler component replacements at Unit 1 and 2 were the costliest capital projects ever done at the Rush Island plant. Golden Test., Tr. Vol. 8-A, 23:7-19. By way of comparison, Rush Island's entire annual O&M budget for the Rush Island plant was about $25 million. Meiners Test., Tr. Vol. 7-B, 23:24-24:2.

183. The boiler component replacement projects were among the most expensive boiler projects that Ameren identified to EPA as ever having been undertaken at any of its plants. Knodel Test., Tr. Vol. 1-A, 81:9 – 82:8.

III. THE 2007 AND 2010 BOILER UPGRADES EACH RESULTED IN A SIGNIFICANT NET EMISSIONS INCREASE OF SO_2 WITHIN THE MEANING OF THE PSD REGULATIONS

184. The 2007 and 2010 boiler upgrades triggered PSD if: (1) Ameren should have expected them to result in a significant (i.e., more than a 40 tons-per-year) SO_2 increase; or (2) a 40 tons-per-year SO_2 increase related to the boiler upgrades actually occurred. *Ameren SJ Decision*; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

185. As described further below, Ameren should have expected the 2007 and 2010 boiler upgrades to increase the availability of the units, thereby resulting in more than 40 tons per

year of increased SO_2 emissions. At both units, these availability improvements resulted from eliminating significant outages and derates that had been plaguing the boilers prior to the upgrades. Removing the problems that had been limiting their pre-project availability should have been expected to increase their post-project operations and emissions. In addition, for at least the 2010 boiler upgrade, Ameren should have expected the new economizer, reheater, and air preheaters to increase the maximum megawatt generating capability of the unit, resulting in increased annual emissions.

186. In addition, availability and hours of operation of Units 1 and 2 actually increased by an amount greater than that required to trigger PSD, just as Ameren expected, as did the megawatt capability of Unit 2.

187. Evidence for these expected and actual increases is found in Ameren's documents and project justifications, in its GADS and other operational data, and in the results of a computer modeling program called ProSym that Ameren uses to simulate the operations of its generating units. The United States' emissions experts, Mr. Koppe, Dr. Sahu, and Dr. Hausman, explained how this evidence demonstrates that the availability and capability improvements at Rush Island Units 1 and 2 would be expected to, and did, far exceed the 40 tons-per-year PSD threshold for SO_2. After a brief overview, the specific evidence supporting a finding that the 2007 and 2010 boiler upgrades resulted in significant SO_2 increases is reviewed in further detail below.

A. Overview

188. The Rush Island units are low-cost, baseload units, meaning that they will operate any additional hours that they are made available to operate. FOF 6. As some of the most cost-effective units in a large and interconnected electricity supply system that is vastly larger than

any individual unit, it was not a lack of demand that was holding the units back prior to the 2007 and 2010 boiler upgrades. These "work horse" units were already made to run every hour they were available to run. What held the units back prior to their upgrades was the forced outages and load limitations that were plaguing the boilers as a result of burning a coal for which they were not designed, along with the fact that key boiler components had degraded as they neared the end of their design lives. Fixing those problems was expected to, and did, result in increased operations.

189. Because they lack SO_2 pollution controls, the Rush Island units are very large sources of air pollution. FOF 8, 9. The large size of the units means that very small changes in performance can result in increased SO_2 emissions of more than 40 tons per year.

190. For example, it only takes 21 additional hours of full power operation at either unit to produce more than 40 tons of SO_2. Sahu Test., Vol. 5, 41:3-7, 45:25-46:4. Given that it typically takes two to three days to recover from even a single outage (FOF 35), eliminating just one outage would result in more than 40 additional tons per year of SO_2. Sahu Test., Vol. 5, 46:17-47:2, 62:2-63:10, 94:5-95:23; August 15, 2005 Presentation (Ex. 332), at AM-00966775, 794 (showing *inter alia* that one outage due to the economizer lasts three days).

191. Measured in terms of equivalent availability, it takes only about a 0.3 percentage point (i.e., one-third of a percentage point) increase in availability to produce more than 40 additional tons per year of SO_2 from these units. Hausman Test., Tr. Vol. 4-B, 66:15-25.

192. Similarly, increasing the capability of Rush Island Unit 2 by just 1.7 megawatts would result in an increase in SO_2 emissions of at least 40 tons per year. Sahu Test., Vol. 5, 41:11-14; 46:5-11; Hausman Test., Tr. Vol. 4-B, 58:4-60:2 (one megawatt increase in capacity produces 23 additional tons of SO2).

B. GADS-Based Emissions Calculations for Rush Island Units 1 and 2

193. The United States presented emissions calculations utilizing data generated by Ameren which was transmitted to the North American Electric Reliability Council ("NERC") and maintained in NERC's Generating Availability Data System. As explained above in Subsection II.B.4, GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Ameren and other utilities use GADS data to track the causes of outages and derates so that they can assess the status of plant equipment and predict future availability. FOF 89, 92. As also described above, Ameren specifically uses GADS data to calculate "lost generation" when performing financial calculations to determine whether to perform capital projects. FOF 103.

194. Plaintiff's expert Mr. Koppe, who has been a power plant performance consultant for four decades and helped develop the GADS database, reviewed Ameren's GADS data to determine which outages and derates were caused by problems with the boiler components at issue in this case. FOF 90, 91, 106.

195. Mr. Koppe then quantified the expected effect of the 2007 and 2010 upgrades on availability. In performing his analyses, Mr. Koppe used the same basic approach that he used to assess expected performance impacts in his work for utilities over the past 40 years. Koppe Test., Vol. 3-A, 35:6-9 ("I've seen it used by many different utilities, including Ameren, and I've seen it in various industry publications.")

196. Mr. Koppe concluded that the company should have expected, and did expect, the 2007 and 2010 boiler upgrades to eliminate all of the availability losses that were due to the economizers, reheaters, lower slopes, and air preheaters. Koppe Test., Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Vol. 5, 95:24-97:2. Ameren's project justifications were based on this very

assumption. Koppe Test., Tr. Vol. 3-A, 49:24-51:14. *See* FOF 145, 146, 147. Similarly, the effects of pluggage on the units were expected to be eliminated for at least decades into the future. Koppe Test., Vol. 3-A, 54:16-55:3.

197. Based on Ameren's documents and data, and relying on his decades of experience in the industry, Mr. Koppe then made an engineering judgment on the improvements in availability that would be expected to result from the 2007 and 2010 boiler upgrades. In order to determine whether eliminating the causes of unavailability related to the components at issue would result in an overall increase in unit availability, Mr. Koppe assessed the condition of the rest of the equipment at Rush Island Units 1 and 2 in order to ensure that other problems would not be expected to offset the performance improvements expected from the boiler upgrades. As Mr. Koppe explained, the boiler components replaced by Ameren were the "things that were really hurting them" in terms of availability, as they alone were causing roughly half of all the lost productivity at the units during the baseline period. Koppe Test., Vol. 3-A, 47:7-12; 75:3-11. "[P]roblems with all the rest of the equipment were only half of the losses, and here you had four problems that were half of all the lost productivity." *Id.* 48:2-8. However, he wanted to be sure that "the level of maintenance that was being done" on the remaining parts of the unit that were not being upgraded was sufficient to maintain the overall very good level of performance that those remaining components had experienced. Koppe Test., Vol. 3-A, 56:12-56:25.

198. As part of this review of the entire unit, Mr. Koppe reviewed GADS data and other contemporaneous company data and documents describing the overall condition of the units. Mr. Koppe reviewed, for example, reports identifying all of the maintenance and capital projects done during the outage, unit condition assessments prepared by company engineers, and presentations made by plant engineers to management about the condition of the unit. Koppe

Test., Vol. 3-A, 34:13-21, 51:20-57:17; *see also* GADS Events Data (Pl. Ex. 925), 2007 and 2010 Outage Reports (Pl. Ex. 34 and 46), Condition Assessments (Pl. Ex. 106 and 606), and State of the System Presentations (Pl. Ex. 15, 41, and 111). Based on his review of this evidence, Mr. Koppe concluded that the overall effect of everything else at the plant on availability would not offset the availability gains from the components at issue. Koppe Test., Vol. 3-A, 51:20- 66:5-67:3.

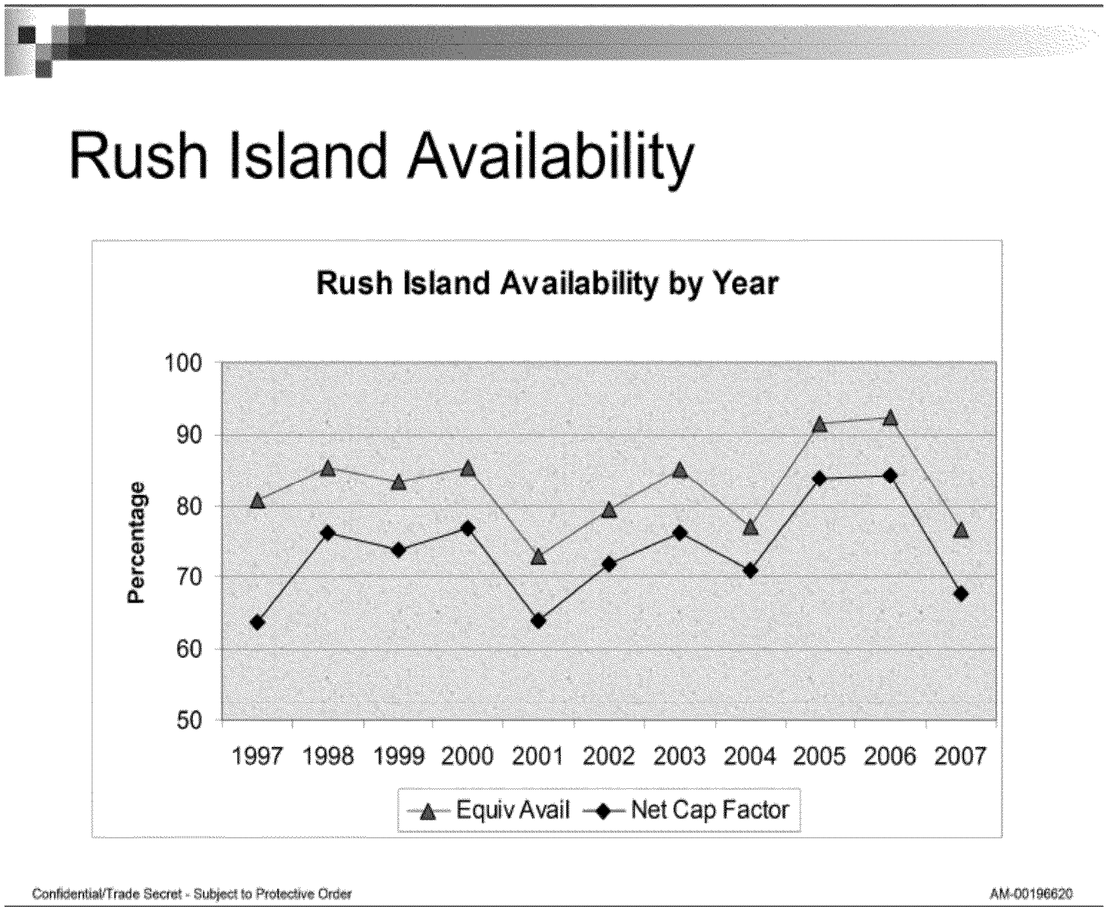
199. Evidence that other problems would not be expected to offset the performance improvements from the 2007 and 2010 boiler upgrades was also provided by Ameren witnesses at trial. As Mr. Naslund testified, as part of the new "super outage" concept that he championed, the company proactively addressed everything that might cause problems in the next six years at a unit to ensure the unit would run as well as possible and "improve unit availability." Naslund Test., Tr. Vol. 6-B 7:1- 8:6. After implementing the super outage process, forced outages in fact went down and availability went up. Naslund Test., Tr. Vol. 6-B, 6:19-25. Mr. Strubberg similarly testified that he was responsible for a condition-based maintenance program called the PRO/PMO program that helped keep the balance of individual components at high availability, and by doing that, it helped keep the units at high availability. Strubberg Test., Tr. Vol. 8-A, 35:21-23, 38:23-24, 39:21-25, 61:5-9, 77:8-12.

200. Once the expected impact on availability is determined for a unit, the next question is to determine whether that increased availability will actually be used to operate more in the future. Whether or not increased availability will result in an additional hour of operation in the future can sometimes be a "tricky question" for some units, "but it's not for these units, because these units operate for almost every single hour that they are able to operate. So if you increase the number of hours a unit is available to operate, that will result in an increase in the

number of hours the unit does operate." Koppe Test., Vol. 3-A, 35:17-26; *see also* Naslund Dep., Sept. 18, 2014, at 55:2-55:7.

201. This direct relationship between availability and generation at Rush Island was also confirmed by modeling performed by Dr. Hausman. As Dr. Hausman explained, if availability is improved, it means the unit can run more hours or it can run at a higher level for more hours. Hausman Test., Tr. Vol. 4-B, 39:9-13. For a relatively low-cost baseload unit, if it is able to produce more, it typically will produce more. As Dr. Hausman explained: "I think that's a fairly fundamental way to look at electricity markets. If I were to run a model and it ran less or used less fuel, there would be something very strange in that." Hausman Test., Tr. Vol. 4-B, 39:16–40:4; *see also id.* at 36:12–21. Dr. Hausman found exactly such a linear relationship between availability improvements and generation at Rush Island. Hausman Test., Tr. Vol. 4-B, 64:10-64:20, 71:7-25.

202. This direct relationship between availability and generation at baseload units like Rush Island was also obvious from presentations prepared by Ameren itself on the importance of availability, which showed availability tightly tracking plant generation. Strubberg Test., Tr. Vol. 8-A, 100:4-6, 100:15-17; 2008 State of the System (Pl. Ex. 15), at AM-00196620.



203. The data also shows a relationship between unit availability and SO_2 pollution, as Ameren's expert Michael King acknowledged at trial. King Test., Tr. Vol. 6-B, 86:2-23.

204. The extraordinarily high use of Rush Island's availability was also confirmed in the GADS data that Mr. Koppe reviewed, which included data on how often the units were placed in a status known as "reserve shutdown." When a unit is in reserve shutdown, it is available to operate but does not for economic reasons. Koppe Test., Tr. Vol. 3-A, at 36:22-37:1.

205. The Rush Island units did not spend a single hour in reserve shutdown during the PSD baseline periods. Koppe Test., Tr. Vol. 3-A, 37:2-7; Naslund Dep., Sept. 18, 2014, Tr. 54:21-55:7; RFA Nos. 189, 192, 193, 203. In the five years before the projects, one of the units operated every single hour it was available, and the other operated 99.9% of the time. Koppe Test., Tr. Vol. 3-A, 37:8-18. That means that if a Rush Island unit "is available to operate another hour, it will operate for that hour; and that, of course, requires burning more coal and generating more emissions." Koppe Test., Tr. Vol. 3-A, 37:19-24; Naslund Test. Vol. 6-A, 50:3-13 (describing Rush Island units as "two workhorses"), 45:3-20 (since 2005, the Rush Island units "were staying up on load at much higher levels around the clock"), 48:7-49:3 (because the Rush Island units are among the cheapest units in MISO, they run a higher percentage of time); Naslund Dep., Sept. 18, 2014, Tr. 55:4-7.

206. Mr. Koppe's quantification of increased unit availabilities caused by the 2007 and 2010 boiler upgrades was then translated into emissions increases by Dr. Sahu, a combustion engineer and environmental permitting engineer, who has performed PSD calculations hundreds of times. Sahu Test., Vol. 5, 34:24-38:14. Dr. Sahu did not assume that Ameren would generate at full capacity every additional hour that it generated. Instead, he applied the same utilization factor that the units experienced during the PSD baseline period. Sahu Test., Tr. Vol 5, 51:5-53:16, 75:3-77:20.

207. Using the same baseline utilization factor is consistent with the fact that the units are baseload units that are used whenever they are available. In addition, the historic utilization factor of the units remained relatively stable, and Ameren documents indicate that it expected the utilization factor of the units to remain relatively stable going forward. Sahu Test., Tr. Vol. 5

57:15-58:21; September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

208. Use of a constant utilization factor was also confirmed by Ameren's witnesses. Ameren expert Marc Chupka opined in his expert report that it "would be reasonable to assume a constant utilization factor for projecting future emissions at least for some period of time" after the projects at issue in this case. Chupka Test., Tr. Vol. 8-B, 77:3-18. Similarly, Sandra Ringelstetter's work papers identified the baseline utilization factor and the utilization factor projected by Ameren for both Unit 1 and Unit 2. For Unit 1, the utilization factor was projected to stay basically the same (a change of 0.09%), while for Unit 2 it was projected to increase by about 2%. Def. Ex. NE, at "RI U1 2007 Summary" and "RI U1 2010 Summary."

209. Using the same utilization factor from the baseline period specifically eliminates the impact of other factors that could cause an increase in utilization of a unit when its availability improves, thus isolating just the effect of the boiler upgrades. For instance, whereas Ms. Ringelstetter identified a 2% increase in utilization factor at Unit 2, Dr. Sahu's use of the baseline utilization factor excludes any effects of increased demand on the units by calculating just the increase that is due to the availability improvements made possible by the upgrades. Sahu Test., Tr. Vol. 5, 75:18-76:5, 153:21-25.

210. In addition, as Dr. Sahu described, the general approach of applying a utilization factor to calculate the additional generation from an expected availability improvement is consistent with Ameren's practices and is well understood in the industry. The same basic formula is found in Ameren's availability worksheets, which translate availability improvements into generation for fuel budgeting purposes, as well as industry documents such as a 1985 study publication of the Electric Power Research Institute ("EPRI"). Sahu Tr., Vol. 5, 53:17-57:5. For

instance, Ameren's availability worksheets provide the following formula for calculating "expected annual plant generation" from an availability change: "Total Net mwhrs" equals "Plant Equiv. Avail. X Utilization Factor." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions." The 1985 EPRI study provides a similar formula. *See* Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011. Similarly, although Ameren has criticized Dr. Sahu's use of utilization factors as applied to both outages and derates in this case, Ameren itself uses utilization factors in a similar way outside of this litigation. For instance, in using a utilization factor to estimate future generation, Ameren's availability worksheets specifically defines the utilization factor as "the percent of mwhrs used after outages and derates." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions."

211. Dr. Sahu's emission calculations also used the same SO_2 emission factor from the baseline period. As with holding the utilization factor constant, reasons for using the baseline emission factor in the calculation of post-change emissions include the fact that Ameren documents indicate that the emission factor was expected to remain fairly stable. Sahu Test. Tr. Vol. 58:22-59:24, 89:6-89:13, September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

212. In addition, the project justification documents for the 2007 and 2010 boiler upgrades made no mention of *any* expected improvements in the gross efficiency of the units, a point that was conceded by Ameren's capability expert. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12; *see also* Sahu Test., Tr. Vol. 5 108:3-21.

213. While Ameren argued that it expected small reductions in auxiliary load as a result of the boiler upgrades, such reductions would result in an improvement in net efficiency, not gross efficiency, and as a result do not affect the amount of coal that the unit is capable of

burning. Rather, they just mean that less power is used to run the plant, so more of the gross generation recovered by the boiler upgrades could be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10. As Dr. Sahu explained, all of his calculations are based on gross megawatts because gross is what relates to how much SO_2 comes out of the boiler. Sahu Test., Tr. Vol. 5 52:16-24, 84:20-24.

214. Similarly, while Ameren did expect some improvement in efficiency at Unit 2 due to the contemporaneous replacement of the low pressure turbine, Dr. Sahu accounted for that in his calculations by factoring out both the additional megawatt capability of the new turbine and the heat rate of the turbine. Sahu Test. Tr. Vol. 5 84:9 – 85:1, 135:23-136:8, 137:9-15; 138:3-10, 181:21 – 182:4. Dr. Sahu's treatment of the low pressure turbine on the expected SO_2 emission rate was consistent with how Ameren itself treated the expected effect of the turbine outside of this litigation. For instance, Ameren's financial analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts, but would not result in the unit burning any less coal. Pl. Ex. 48, at "Data Entry" sheet (rows 149-152, col. D (and comment box) (showing that Ameren did not include efficiency benefit inputs for "decrease in fuel usage")), Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9. As Dr. Sahu noted, Ameren's financial analysis shows that there was no expected fuel decrease associated with the capacity increase. Sahu Test. Tr. Vol. 5, 97:3 - 99:4.

215. Use of a constant emission factor was also corroborated by the United States' other experts. As Dr. Hausman explained, when a baseload unit like the Rush Island units is modified to become more efficient, it allows the unit to generate more electricity while consuming the same amount of coal. Hausman Test., Tr. Vol. 4-B, 37:6–18. Because a baseload plant has essentially an unlimited market for its very low-cost power, if it becomes more

efficient, it will burn the same amount of coal but produce more energy than it can sell into the market. Hausman Test., Tr. Vol. 4-B, 38:7–11. As a result, as Mr. Koppe also explained, the separate efficiency gain from the turbine would result in increased megawatts but would not change the full load heat input to the boiler. Koppe Test., Tr. Vol. 3-B, 29:9-32:9. This was also consistent with Ameren employee Jeff Shelton's testimony that a more efficient turbine can allow a unit to make more megawatts with the same amount of heat input. Shelton Test., Tr. Vol. 10-A, 85:14-20, 85:5-9.

216. Finally, use of a constant emission rate was also borne out by Ameren's operating data as reported to EPA, which confirmed that the post-project emission rate at Unit 1 stayed relatively constant, and actually increased somewhat at Unit 2 as compared to the PSD baseline periods. Sahu Test., Tr. Vol. 5, 109:14-22. At Unit 1, reported heat rate deteriorated slightly, from 9,282 Btu/Kwh to 9,447 Btu/Kwh, and the unit emitted approximately 21 more pounds per hour of SO_2 than it had in the baseline. Sahu Test., Tr. Vol. 5 110:6-111:6; Knodel Test., Tr. Vol. 1-A, 110:8-24. At Unit 2, reported heat rate deteriorated from 8,800 Btu/Kwh to 9,676 Btu/Kwh, and the unit emitted approximately 456 more pounds per hour of SO_2 than it had in the baseline. Knodel Test., Tr. Vol. 1-A, 111:8-20. Sahu Test. Tr. Vol. 5, 112:21-24. As a result, for every additional hour that Rush Island Units 1 and 2 were able to operate in the post project period, they actually emitted more SO_2 per hour.

217. Because Dr. Sahu's calculation is based on the incremental impact of the projects on unit performance calculated by Mr. Koppe, his entire predicted increase is related to the project. Sahu Test., Tr. Vol. 5, 49:21 – 50:3, 60:13-18, 61:15-17, 73:6 – 74:4, 77:11-20, 84:15 – 87:10.

218. Ameren presented testifying expert Michael King to critique the approach used by Mr. Koppe and Dr. Sahu. But Mr. King agreed that Mr. Koppe and Dr. Sahu "have the appropriate experience to estimate the effect of modifying a power plant on generation [and] emissions." King Test., Tr. Vol., 6-B, 65:17-21.

219. Another Ameren testifying expert, Marc Chupka, conceded that the method used by Mr. Koppe and Dr. Sahu for determining PSD emissions increases has at least been "well-known in the industry" since the first enforcement cases were filed in 1999. Mr. Koppe testified that he and Dr. Sahu had used the same basic formula in this case that he and other utilities have used for decades. Koppe Test., Tr. Vol. 3-A, 35:6-9; *see also* Sahu Test., Tr. Vol. 5, 53:17-57:5 (discussing Ameren and industry documents). Mr. Chupka himself has been asked to analyze utility projects using the same method employed by Mr. Koppe and Dr. Sahu numerous times. Chupka Test., Tr. Vol. 8-B, 74:14-21, 75:5-10.

1. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 1

220. As described further below, Ameren should have expected an increase of at least 600 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2007 boiler upgrade.

221. The PSD "baseline" period used by Ameren for Unit 1 in this litigation was the highest 24-month period of emissions in the five years before the 2007 boiler upgrade, which was February 2005 through January 2007. During that period, Unit 1 emitted 14,874 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 49:8-20; Knodel Test., Tr. Vol. 1-A, 95:6-25.

222. During this baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year,

which is roughly equivalent to 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id.*

223. As explained by Mr. Koppe, the problems associated with the Unit 1 reheater, economizer, air preheater, and lower slopes caused about 50% of all the availability losses at Unit 1 during the baseline period. Koppe Test., Tr. Vol. 3-A, 47:7-12; 48:2-8.

224. These problems reduced Unit 1's availability during the baseline period by 3.8 percentage points. Sahu Test., Tr. Vol. 5, 63:11-64:5. Unit 1's availability was 92.1% during the baseline. Koppe Test., Tr. Vol. 3-A, 48:9-11. The average annual availability of Unit 1 over the entire five-year pre-project period was 87.5%. *Id.* 48:15-23

225. Based on his analysis of Ameren's operating data, including GADS, as well as contemporaneous documents, Mr. Koppe concluded that Ameren should have expected the 2007 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, lower slopes, and air preheater components. Koppe Test., Tr. Vol. 3-A, 48:24-49:6, 66:5-12; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2.

226. Company documents and witnesses confirm that Ameren actually had such an expectation. Ameren expected that as a result of the 2007 boiler upgrade, availability losses attributable to the replaced components would be completely eliminated for years in the future. Meiners Test., Vol. 7-B, 40:1-18 ("Q. Right. If you do the project, in the future you won't have those causes of unavailability, right? A. Correct."); Boll. Test., Vol. 8-B, 46:11-47:10 ("that's probably a good bet"); FOF 145, 146, 147.

227. Based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2007 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 1. Koppe Test., Tr. Vol. 3-A, 34:13-21, 51:20-55:17, 66:5-12. The impact of the project alone would be to increase the availability of Unit 1 by 3.8 percentage points over baseline availability by eliminating all 336.1 EFPH of availability losses related to the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2. If the four components had not been replaced, the availability of the unit would have been expected to decrease. Koppe Test., Tr. Vol. 3-A, 66:13-67:3.

228. Similar projected increases can be found in Ameren's availability forecasts. For example, the forecast for the 2006 Fuel Budget projected that Unit 1's long-term average availability would be 95.0% as a result of the "boiler improvements" done during the Unit 1 outage. This represents an increase of 7.5% over Unit 1's five-year pre-project average and about a 3% increase over Ameren's high baseline emissions period (a 3 percentage point improvement is the equivalent of about 10 more days of operation). Koppe Test., Tr. Vol. 3-A, 61:20-65:8; Meiners Test., Vol. 7-B, 39:16-25; September 23, 2005 Email (Pl. Ex. 214); September 28, 2005 Email attaching Availability Worksheet (Pl. Ex. 215), at Rush tab.

229. Ameren's 2006 Fuel Budget forecast showed a 4.2 percentage point improvement in Unit 1's forced outage rate after the work. Def. Resp. to Interrogatory No. 68; Boll Test., Vol. 8-B, 42:19-44:1. Ameren's Rule 30(b)(6) witness, David Boll, admitted in deposition testimony that the 4.2% improvement in the outage rate was "most probably due to the major outage" and could provide no other reason for the improvement. Boll Test., Tr. Vol. 8-B, 44:2-45:5; Boll

Dep. Dec. 12, 2013, Tr. 122:13-123:2; Aug. 17, 2007 Email and Attached Spreadsheet (Pl. Ex. 523), AM-02264672.

230. Similarly, Rush Island Plant Manager Robert Meiners gave a presentation to Ameren senior executives in which he discussed the condition of the reheater, economizer, air preheater, and lower slopes on Rush Island Unit 1 and the efforts to replace those components. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's long-term availability would increase by almost 5 percentage points, from about 90% in 2005-2006 to 95% after both outages had been completed. Mr. Meiners admitted that even a one percent change in availability would be a significant change. Meiners Test., Tr. Vol. 7-A, 68:8-18; Tr. Vol. 7-B, 27:21-24, 28:10-20, 31:15-21, 33:4-6; Rush Island Business Plan Presentation (Pl. Ex. 126), at AM-02625397.

231. Before the Unit 1 project had been approved, Ameren was not forecasting an increase in availability; instead its forecasts were that availability would remain flat – 91%. That is because all of the other work done during the 2007 outage would maintain availability but would not cause an increase in availability. Koppe Test., Tr. Vol. 3-A, 65:13-66:4, 66:13-67:3.

232. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2007 boiler upgrade into emissions and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Vol. 5, 39:23-25, 40:21-24, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 607.8 tons per year of SO_2 over the PSD baseline emissions as a result of the replacement of the economizer, reheater, lower slopes, and air preheater. Sahu Test., Tr. Vol. 5, 49:8-50:14, 57:15-59:5, 92:22-93:17; 115:17-20.

233. Even without counting the effects of derates and focusing just on the outages caused by the components, the 2007 boiler upgrade would allow the unit to operate 246 more hours or about 10 more days per year by eliminating the outages associated with the reheater, economizer, lower slopes, and air preheaters. By itself, this would cause a more than 400 ton-per-year increase in emissions of SO_2. Koppe Test., Tr. Vol. 3-A, 49:12-23; Sahu Test., Vol. 5, 65:12-66:22.

2. Rush Island Unit 1 actual emission increases

234. Just as Ameren expected, Unit 1 experienced a substantial increase in availability following the 2007 boiler upgrade. In 2008, Rush Island Unit 1 had an equivalent availability of 96.77%. This was the highest equivalent availability of any unit in the entire Ameren system in 2008. Unit 1's equivalent availability in 2008 was higher than any 24-month period of equivalent availability since the Rush Island plant first began tracking availability data in 1982 and higher than any 12-month period since 1990. Anderson Test., Tr. Vol. 7-A 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-15, 55:18-23, 56:12-16; Strubberg Test., Tr. Vol. 8-A, 94:3-8, 95:1-4; Def. Resp. to RFA 299; Jan. 9, 2009 Email (Pl. Ex. 104), at AM-02272427 ("Rush Island 1 had the highest EAF [equivalent availability factor] at 96.77%"); *see also* Koppe Test., Tr. Vol. 3-A 67:4-69:3.

235. Rush Island Plant management received significant salary bonuses relating the Rush Island's availability in the year 2008, whereas they had received no such bonuses for the year before. Strubberg Test., Vol. 8-A, 100:23-102:3; Def. Response to Interrogatory No. 65.

236. In April 2009, Rush Island Unit 1 set an "all-time record run for days on line," breaking the "old plant record of 211 days [that] was set in 1990." April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; Strubberg Test., Tr. Vol. 8-A,

60:7-61:18 (admitting that Unit 1 had an equivalent availability of more than 98% during this period). Ameren Vice President Mark Birk specifically called out the replacement of the "reheater, economizer, and lower slopes" in 2007 as having "paid off" when he reported Unit 1's record availability to Ameren's CEO Warner Baxter. April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; *see also* Koppe Test., Tr. Vol. 3-A 69:12-70:12.

237. The GADS data confirmed that the cause of the improved availability was the improved performance of the components at issue that were replaced as part of the 2007 boiler upgrade. As Ameren should have expected, and did expect, all of the availability losses due to problems in the reheater, economizer, lower slopes, and air preheater were eliminated after the 2007 boiler upgrade. As a result, component-related availability losses were reduced from 336.1 EFPH per year to zero. Availability losses due to everything else also decreased slightly. Koppe Test., Tr. Vol. 3-A, 70:17-71:2, 81:8-17; Sahu Test., Tr. Vol. 5, 64:8-21.

238. Further reflecting the actual performance improvements resulting from the 2007 boiler upgrade, Ameren's reported GADS data further show that Unit 1's equivalent availability actually increased over the baseline period by 4.3 percentage points, from 92.1% to 96.4% in the relevant post-project period. *Id.*; Sahu Test., Vol. 5, 64:24-65:3; Koppe Test., Tr. Vol. 3-A, 71:18-72:14.

239. None of the availability improvements that actually occurred at Unit 1 would have happened if the reheater, economizer, lower slopes, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Test., Vol. 7-B, 57:11-16.

240. Similarly, Ameren's reported GADS data shows that Unit 1's operating time increased from 8,208 hours per year in the baseline to 8,568 hours per year during the highest post-project period of emissions, for an increase of 360 hours. This increase in operating hours

included the effect of eliminating the 246 outage hours per year during the baseline period that were caused by problems associated with the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 73:3-15; Sahu Test., Tr. Vol. 5, 65:12-66:22, 109:7-13.

241. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 43,957,163 MMBtu per year in the baseline period to 45,442,171 MMBtu per year in the relevant post-project period. Sahu Test., Vol. 5, 109:25-110:5.

242. Similar increases are shown in Ameren's certified Continuous Emissions Monitoring System ("CEMS") data, which show that Unit 1 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 1's operating time increased by 320 hours per year, from 8,278 hours per year in the baseline to 8,598 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 1 emitted 21 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,593 pounds per hour in the baseline to 3,614 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 110:8-111:7, 112:14-24.

243. Ameren's CEMS data also show that in 2008, the first calendar year after the 2007 boiler upgrade, Rush Island Unit 1 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. 1-A 82:9-19. During the relevant post-project period, Unit 1 emitted 15,539 tons per year of SO_2, which is 665 tons per year more than Unit 1 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 49:8 – 20, 111:7-16; Knodel Test., Tr. Vol. 1-A, 95:6-25.

244. Eliminating 246 outage hours by replacing the reheater, economizer, lower slopes, and air preheater, by itself, equates to SO_2 emissions of more than 400 tons per year. Sahu Test.,

Tr. Vol. 5, 41:3-7, 45:25-46:4, 65:12-66:22. Because all of the availability losses caused by the reheater, economizer, and air preheater in the baseline were eliminated (336 EFPH and 246 outage hours), (Koppe Test., Vol. 3-A, 67:7-73:19), it is clear that at least 40 tons of the overall 665 ton increase in actual emissions is related to the increased equivalent availability and additional operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 39:13-17, 64:6-66:22.

3. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 2

245. As described further below, Ameren should have expected an increase of approximately 400 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2010 boiler upgrade.

246. The PSD "baseline" period used by Ameren for Unit 2 in this litigation was the highest 24-month period of emissions in the five years before the 2010 boiler upgrade, which was April 2005 through March 2007. During that period, Unit 2 emitted 14,287.7 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 72:17-73:5; Knodel Test., Tr. Vol. 1-A, 91:4-17.

247. During this baseline period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:19.

248. These problems reduced Unit 2's equivalent availability during the baseline period by 2.8 percentage points. Sahu Test., Tr. Vol. 5, 119:6-17; Koppe Test., Tr. Vo. 3-A

76:17-22. According to the company's GADS events data, Unit 2's availability was 94.5% during the baseline. The average annual availability of Unit 2 over the entire five-year pre-project period was about 92%. Koppe Test., Vol. 3-A, 75:3-75:23, 76:17-22.

249. The problems associated with the Unit 2 reheater, economizer, and air preheaters caused about 50% of all the availability losses at Unit 2 during the baseline period. Koppe Test., Tr. Vol. 3-A, 75:3-11; Sahu Test., Tr. Vol. 5, 79:20-80:12.

250. Based on his analysis of Ameren's operating data, including GADS, as well as other company documents, Mr. Koppe concluded that, just as at Unit 1, Ameren should have expected the 2010 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:5.

251. As at Unit 1, based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2010 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 2. Koppe Test., Vol. 3-A, 34:7-21, 55:4-57:22, 73:25-74:2, 77:9-79:14, 84:4-13. The impact of the project alone would be to increase the availability of Unit 2 by 2.8 percentage points over baseline availability by eliminating all 243 EPFH of availability losses related to the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:8.

252. Similar projected increases can be found in Ameren's project documents and availability forecasts, which indicate that Ameren should have expected and did expect that Unit 2's equivalent availability would be similar to what Unit 1 achieved after the 2007 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 77:9-20; Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

253. For instance, Ameren updated its financial justification for the Unit 2 outage in 2009, and included in that justification was the expectation that Unit 2's availability would be as high as Unit 1's availability was in 2008 – almost 97%. Koppe Test., Tr. Vol. 3-A, 77:21-78:19; Meiners Test., Tr. Vol. 7-B, 45:8-25, 48:4-49:5, 50:14-51:2; Unit 2 ELT Progress Report, (Pl. Ex. 110), at AM-02465690; Updated Financial Analysis (Pl. Ex. 48), at "Data Entry" tab (row 155, col. F (and hidden comment: "4.3% gain related to outage work (u2 vs. u1)"). That would be a 4.3 percentage point improvement in equivalent availability over what Unit 2 had experienced in 2008, and would represent about 15 additional days of operation for Unit 2. *Id.*; Meiners Test., Vol. 7-B, 18:22-19:16 (the EAF input in the analysis was the equivalent of "15 days of generation").[2] Mr. Meiners personally assured Ameren's CEO Warner Baxter that inputs used in the updated financial analysis for the Unit 2 outage were accurate. Meiners Test., Tr. Vol. 7-B, 46:9-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits.").

254. Unit 1's availability in 2008 was 96.77%. During the same year, Unit 2's availability was 92.42%. RFAs 299 and 300; Anderson Test., Tr. Vol. 7-A, 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-20.

255. All or essentially all of the 4.2 percentage point improvement was related to the components at issue. All of the other work done during the outage was done to keep the performance of the rest of the unit from getting worse but would not improve availability. Koppe Test., Vol. 3-A, 78:23-79:6; Koppe Test., Tr. Vol. 4-A, 99:22-100:2, 103:14-104:25; *see also* Meiners Test., Tr. Vol. 7-B, at 57:11-16 (none of the availability improvement would have

[2] As discussed above, the final EAF input was adjusted downward by 0.1%, from 4.3% to 4.2%, as result of eliminating the lower slope replacement from the final scope of the project. FOF 148.

occurred if the components at issue had not been replaced); February 6, 2007 Email (Pl. Ex. 103) ("In reality, until we have the economizer replacement, Unit 2's forced outage is going to get worse, not better.").

256. Ameren's updated Full Work Order Authorization for the reheater and economizer replacements similarly indicated that Ameren expected the "boiler modifications [to] result in an improved operation of the unit that is at least equal to, if not better, than that currently expected with Unit 2 which had similar modifications in 2007." The authorization quantified this amount as an expected "3-4% improvement in the equivalent availability of the unit." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; Birk Dep., Sept. 24, 2013, Tr. 194:1-195:13. Mr. Meiners confirmed that the availability input used for the justification was almost 97%. Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

257. Ameren also should have expected Unit 2's long-term average equivalent availability to increase from 92% to 95%. Because there is a 2-3% variation in long-term forecasts, Ameren understood that Unit 2's highest annual availability after the 2010 boiler upgrade would be 97-98%. Koppe Test., Tr. Vol. 3-A, 76:17-22, 79:7-14; Meiners Test., Tr. Vol. 7-B, 54:14-55:6; Hausman Test., Tr. Vol. 4-B, 65:9–19. Other forecasts done before the boiler upgrade also predicted greater than 95% as a long term availability after the Unit 2 outage. *See* Updated 2008 Fuel Budget forecast (Pl. Ex. 252) (projecting 97% EAF for Unit 2 after outage); Meiners Test, Vol. 7-B, 51:18-52:7.

258. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2010 boiler upgrade into emissions increases, and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Tr. Vol. 5,

39:23-25, 40:21-24, 78:13-19, 99:13-100:11, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 414.5 tons per year of SO_2 due solely to the improvements in equivalent availability that Ameren should have expected from the replacement of the economizer, reheater, and air preheater. Sahu Test., Tr. Vol. 5, 73:6-74:14, 115:17-20.

4. Rush Island Unit 2 actual emission increases based on availability

259. Just as Ameren expected, Unit 2 experienced a substantial increase in availability following the 2010 boiler upgrade. During the relevant post-project period, as Ameren should have expected and did expect, there were no availability losses at all due to the reheater, economizer, and air preheater. Availability losses due to all the rest of the equipment at the unit essentially stayed the same. Koppe Test., Tr. Vol. 3-A, 80:7-23; Sahu Test., Tr. Vol. 5, 80:13-81:1, 82:13-83:5; *see also* Pl. Ex. 746 (work paper showing no GADS events for reheater, economizer, and air preheater during post-project period).

260. Overall equivalent availability increased by 2.9 percentage points, from 94.5% in the baseline to 97.4% during the first 12 months after the 2010 boiler upgrade, the relevant post-project period in the case. Unit 2's equivalent availability during this period was higher than any 24-month period in the history of the plant, going back to when Ameren first began tracking availability data in 1982, and higher than any 12-month period since 1987. Koppe Test., Tr. Vol. 3-A, 88:24-89:6; Anderson Test., Tr. Vol. 7-A, 58:3-9, 58:24-59:13; *see also* Sahu Test., Tr. Vol. 5, 81:2-15; Pl. Ex. 746.

261. Ameren's witness, Scott Anderson, referred to the increase in Unit 2's availability before and after the 2010 outage as "night and day." Anderson Test., Tr. Vol. 7-A, 58:7-9 (It is "obvious that the plant went way too long without a planned outage before correcting the

problems that it had. I mean, it's night and day."). Ameren had specifically called Mr. Anderson to discuss what the GADS data showed about the availability of the Rush Island units. Anderson Test., Tr. Vol. 7-A, 31:23-32:19.

262. None of the availability improvements at Unit 2 would have occurred if the reheater, economizer, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Dep., Tr. Vol. 7-B, 57:11-16.

263. According to Ameren's GADS data, Unit 2's operating time increased from 8,408 hours/year in the baseline period to 8,583 hours/year in the applicable post-project period, for an increase of 175 hours per year. This increase in operating hours included the effect of eliminating 146 outage hours per year in the baseline period caused by problems associated with the reheater, economizer, and air preheater. Sahu Test., Vol. 5, 83:8-22, 112:6-11, 158:3-8; Koppe Test., Vol. 3-A, 83:20-84:3; *see also* Koppe Test., Tr. Vol. 4-A, 115:18-25 (If "half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same, … then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.").

264. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 42,326,578 MMBtu per year in the baseline period to 47,660,058 MMBtu per year in the post-project period. Sahu Test., Tr. Vol. 5, 112:17-20.

265. Similar increases are shown in Ameren's certified CEMS data, which show that Unit 2 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 2's operating time

increased by 123 hours per year, from 8,478 hours per year in the baseline to 8,601 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 2 emitted 456 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,371 pounds per hour in the baseline to 3,827 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 111:8-20, 112:3-10, 113:1-21.

266. Ameren's CEMS data also show that in 2011, the first calendar year after the 2010 boiler upgrade, Rush Island Unit 2 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. I-A 82:9-19. During the applicable period of highest post-project emissions, Unit 2 emitted 16,458.1 tons per year of SO_2, which is 2,171 tons per year more than Unit 2 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 74:15-18, 78:9-12, 112:25-113:3; Knodel Test., Tr. Vol. 1-A, 97:11-98:5.

267. Because all of the availability losses and outage hours caused by the reheater, economizer, and air preheater in the baseline were eliminated (243 EFPH and 146 outage hours), and it only takes an additional 21 hours of operation for Rush Island Unit 2 to emit 40 tons of SO_2, at least 40 tons of the overall increase in emissions at Unit 2 are related to the increased equivalent availability and operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 80:13-84:4, 115:10-116:4, 165:15-25.

C. Emissions Increases Based on Unit 2 Capability Analyses

268. In addition to improving the availability of both units, the 2010 boiler upgrade should have been expected to increase the capability of Rush Island Unit 2. As described further below, because Unit 1 experienced a capability increase after the 2007 boiler upgrade, Ameren should have expected – and did expect – a similar increase to occur after the 2010 boiler upgrade at Unit 2. Koppe Test., Tr. Vol. 3-B, 19:20-25.

1. The expected capability and efficiency impact of the Unit 2 boiler upgrade

269. In October 2007, Ameren engineers noted that Unit 1 had experienced an increase in capability due to the boiler component replacements, and Rush Island Supervising Engineer Gregory Vasel asked the Plant's Performance Engineer James Bosch to quantify that increase: "I looked at the 2006 [project justification] for the U2 economizer, reheater, and lower slope, and it projects *no* increase in capacity. I asked Mr. Bosch to quantify the capacity increase we've realized on U1, as well as the aux power reduction we're seeing with running one of our ID fans in low speed. … I communicated this to Leo Reid, who is working on the [project justification] for Bob Schweppe." Vasel Email (Pl. Ex. 130), at AM-02635983 (emphasis in original); Koppe Test., Tr. Vol. 3-B, 12:17-13:4.

270. Mr. Bosch reviewed full load tests from before and after the Unit 1 outage and determined that there had been a 19 MW increase in Unit 1's gross capability (from 611 MW to 630 MW). Pl. Ex. 130, at AM-02635983. Ameren project engineer Leo Reid incorporated a "16MW increase in generating capacity" into an updated financial analysis for the Unit 2 project. *Id.* at AM-02635982. In assessing what caused the capacity increase, Mr. Vasel instructed Mr. Bosch to look at the "delta P reductions of the [air preheater] vs. ([reheater] + economizer) …" *Id.* at AM-02635981. The updated financial analysis was provided by Mr. Vasel to Ameren's Director of Power Operations Robert Meiners, and was described as the "best information" that the plant had at the time. *Id.*

271. Mr. Koppe reviewed Ameren's full load tests and Plant Information data ("PI data") for Unit 1 and confirmed Mr. Bosch's analysis showing a 19 megawatt increase in capability had occurred at Unit 1. Mr. Koppe also reviewed the Plant Information data and other company documents and confirmed that there was a "dramatic drop" in the differential pressures

in the air preheater and economizer after the Unit 1 boiler upgrade. For example, a graph presented in Ameren's 2008 State of the System meeting indicates a "tremendous reduction" in the air preheater delta P from 14 to 5 inches of water. An air preheater delta P of 14 inches is "extremely high," and a reduction to 5 inches shows that Unit 1's capability was no longer limited by the effects of pluggage. Koppe Test., Vol. 3-A, 22:13-25:4; Vol. 3-B, 13:5-23; 2008 State of the System, Pl. Ex. 15, at AM-00196909; *see also* Sind Test., Vol. 9-B, 26:16-18 (air preheater differential pressures above 11 inches are "extremely high"); Cardinale Dep., July 31, 2014, Tr. 84:3-21; *see* FOF 75, 76 (showing graphs).

272. Ameren subsequently increased Unit 1's capability rating to 630 MW gross. Mr. Bosch reported the results of his quantification of a 19 MW increase in an email dated November 1, 2007. Vasel Email (Plaintiff's Exhibit 130), at AM-02635983. The document officially revising the 2008 capability stated that the increase was based on plant staff's request to reflect performance improvements following the spring 2007 outage during which the reheater, economizer, and air preheaters were replaced. Shelton Test., Tr. Vol. 10-A, 89:10-23.

273. In February 2008, Rush Island Plant Manager David Strubberg gave a presentation at a State of the System meeting in which he discussed the "Future Priorities" for Rush Island. Among the priorities discussed by Mr. Strubberg was a "25-30 MW" capability increase expected as a result of the boiler component and air preheater replacements and a separate 13 MW capability increase expected due to the replacement of the LP turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628; Koppe Test., Vol. 3-B, at 24:2-25:2.

274. A few months later, in June 2008, Rush Island Superintendent of Operations Andrew Williamson was asked by Ameren's Dispatch Coordinator Steve Schoolcraft to estimate the predicted capability of Unit 2 following the outage. Mr. Williamson noted: "We did

experience a substantial increase on Rush 1 due to increased boiler performance with the new RH/Econ/APHs and should reasonably expect the same for Rush 2." June 2008 Email (Pl. Ex. 267), at AM-02660313. Mr. Williamson predicted that Unit 2's capability would be 625 MW (net), which is about 655 MW (gross), after the outage. Of this, Mr. Williamson predicted that the boiler component replacements at issue, alone, would increase Unit 2's capability to 615 MW (net), or roughly 645 MW (gross), and replacement of the low pressure turbine would add another 12-15 MW. *Id.* at AM-02660307-08; Koppe Test., Tr. Vol. 3-B, 25:3-26:11; Williamson Test., Tr. Vol. 9-B, 40:10-41:2, 41:7-42:1.

275. Later in 2008, Mr. Williamson's prediction that Unit 2 would be able to achieve 625 MW (net) after the work was incorporated into Ameren's 10-Year System Plan, and represented an increase of 44 MW over the capability of Unit 2 at the time. This was the only increase in capability across the entire Ameren system noted in the 10-Year Plan. 10 Year Plan Spreadsheet (Pl. Ex. 251), at "UE" tab (hidden comment to row 20, col. F: "Rush Island unit 2 net output is increased from 581 to 625 (44 MW increase) provided by Steve Schoolcraft"), and "UE Changes" tab (row 54: "Rush Island 2's net output were changed to 625 MW per the plant's request …"); Koppe Test., Tr. Vol. 3-B, 26:16-27:6.

276. As described above, in 2009, Ameren completed an updated financial analysis for the Unit 2 outage. In addition to improvements in equivalent availability, Ameren's updated analysis included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet, row 147, col. B & E; Koppe Test., Tr. Vol. 3-B, 28:2-12, 30:4-32:23.

277. The capacity increase input in the financial analysis was based on Ameren's estimate that replacing the economizer, reheater, and air preheater would allow Unit 2 to produce

30 more MW of capacity during the summer and 20 more MW for the rest of the year. The capability benefits were based on the combined effect of all three component replacements, and represented an increase over what Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet, row 147, col. B & E (formula bar: 0.25*30 + 0.75*20); July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment"), Pl. Ex. 347, at AM-02637758 (same), June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632842 (same).

278. In the Fall of 2009, Ameren also completed updated Full Work Order Authorizations for the replacement of the reheater, economizer, and air preheater. Consistent with previous projections, Ameren engineers described that a "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160. Similar statements were made in other Ameren documents. *See, e.g.,* Pl. Ex. 893, at AM-02229417 ("Approximately 30 megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters.").

279. Based on his review of Ameren's documents and data, Mr. Koppe confirmed that Ameren should have expected, and did expect, an increase in Unit 2's capability of at least 22 MW (gross) as a result of replacing the economizer, reheater, and air preheater. That additional capability would result from eliminating the effects of pluggage and allow Unit 2 to burn more coal per hour. Koppe Test., Vol. 3-B, 33:14-34:1; *see also* Vol. 3-A, 27:18-25, 29:2-8, Vol. 4-A, 46:23-47:18.

280. Ameren should not have expected any sustainable change in gross efficiency as a result of the reheater, economizer, and air preheater replacements. There was no expected efficiency benefits used as an input in the original Unit 2 project justification. The updated project justification included a 0.5% reduction in auxiliary load for the economizer and air preheater replacements, which equates to about 3 MW of net capability. The 3 MW reduction in auxiliary load would improve net efficiency, not gross efficiency, and would not be expected to change the full load heat input of Unit 2. FOF 117. Ameren did not project any decrease in fuel usage as a result of any efficiency changes associated with the component replacements. Koppe Test., Vol. 3-A, 5:13-20, Vol. 3-B, 28:13-29:8, Ex. 110, at AM-02465690 Pl. Ex. 48, at "Data Entry" sheet, at rows 149-152 (no decrease in fuel usage input for auxiliary load reductions).

281. Ameren's best expectation for the effect of the LP turbine on unit efficiency is that it would increase Unit 2's capability by 12 MW, which is the amount that was guaranteed by the vendor. Sind Test., Vol. 9-B, 20:3-12, 26:23-28:3. Ameren's updated financial analysis for the Unit 2 outage estimated that the efficiency improvements associated with the LP turbine would allow Unit 2 to produce 15 more MW of capability. The analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts but would not result in the unit burning less coal. Pl. Ex. 48, at "Data Entry" sheet, rows 149-152 (no "decrease in fuel usage" input for turbine replacement) Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9.

2. Actual increases in Unit 2's capability

282. Consistent with the results achieved after the Unit 1 project, there was a big improvement in Unit 2 in the air preheater differential as a result of the air preheater replacements, where the differential pressure went from about 15 inches of water to about 5

inches. Koppe Test., Tr. Vol. 3-A, 25:22-27:17; Sind Test., Tr. Vol. 9-B, 25:6-26:2 (Mr. Sind's capacity analysis showed a big decrease in air preheater differential pressure from 13-14 inches to less than 6 inches); Williamson Test., Tr. Vol. 9-B, 44:7-14 (differential pressure of 15 inches indicates "high pluggage").

283. The improvement in the air preheater differential pressure, along with improvements in the other limitations (economizer differential pressure and ID fan suction pressure), meant that Unit 2's capability and ability to burn coal was no longer limited by pluggage after the Unit 2 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 27:18-25, 28:7-14, 29:2-8. During the PSD baseline period, when the unit was experiencing extensive pluggage, the average full load capability of Rush Island Unit 2 was only 620 gross megawatts. FOF 120; Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; PX 928 (Rule 1006 summary of full load tests for Unit 2).

284. The increase in capability at Unit 2 was evident as soon as the unit returned to service after the 2010 outage. For example, on May 29, 2010, Ameren conducted a Full Load Test in which Unit 2's gross capability was measured to be 655 MW, exactly as Mr. Williamson had predicted in 2008. Compare May 29, 2010 Full Load Test (Pl. Ex. 236) (655.13 gross megawatts), with June 2008 Email (Pl. Ex. 267), at AM-02660307-08 (predicting 625 net megawatt); Williamson Test., Tr. Vol. 9-B 41:14-16 (confirming that 625 net megawatts equates to 655 gross megawatts); *see also* Sind Test., Tr. Vol. 9-B, 29:19-30:16. A full load test conducted in October 2010, after the unit had been in service for several months following the boiler upgrade, showed even higher capability. The gross capability measured during that test was 664 MW. October 19, 2020 Full Load Test (Pl. Ex. 913). No capability limitations were noted by plant engineers in either test report.

285. Similarly, in October 2010, Ameren performed a test to verify that the new reheater, economizer, and air preheater had satisfied their performance guarantees. Unit 2's capability during the performance test was recorded as about 659 MW (gross). Boiler Performance Test Report (Pl. Ex. 81), at AM-00482381.

286. Ever greater capability was noted among the "Bottom-Line Results" of the Unit 2 outage during the 2010 State of the System Meeting: "679 Gross MWs!" 2010 State of the System (Pl. Ex. 41), at AM-02493751.

287. After the 2010 outage, Ameren also reported a substantial increase in Unit 2's capability to its system operator, MISO, to NERC, and to the Missouri Public Service Commission. Specifically, in September 2010, Ameren reported to NERC that Unit 2's <u>summertime</u> peak capability had increased to 648 MW (gross), 617 MW (net), "due to work completed in the 2010 major boiler outage (replacement low pressure turbines and ***numerous boiler modifications***)." October 27, 2010 MISO Verification Test Data (Pl. Ex. 139), at AM-02663830 (emphasis added). Ameren provided the same information to NERC in September 2010. September 15, 2010 Capability Validation (Pl. Ex. 133), at AM-02645178; *see also* Koppe Test., Tr. Vol. 3-B, 46:6-47:22.

288. Later in December 2010, Ameren responded to a request from the Missouri Public Service Commission to identify any plant upgrades that it expected to result in an increase in the amount of electricity the plant would produce in the future. MPSC Data Request 0257 (Pl. Ex. 222); Koppe Test., Vol. 3-B, 50:22-51:11.

289. Ameren told the Missouri Public Service Commission that the 2010 outage, including the component replacements at issue, would result in a 34 MW increase in Unit 2's capability, which it characterized as having been based on a "significant capacity restoration[]"

of 22 MW and a "true capacity increase[]" of 12 MW. Ameren Resp. to DR 0257 (Pl. Ex. 223); Koppe Test., Vol. 3-B, 51:12-52:22. Joe Sind, the Ameren engineer who performed the analysis supporting Ameren's statements to the Missouri Public Service Commission, confirmed that the reported 12 MW "true capacity increase" was based on the company's best expectation of the impact of the LP turbine replacement on the capability of the unit. Sind Test., Tr. Vol. 9-B, 20:3-12, 27:12-28:3. Mr. Sind's work papers show that his capacity analysis only looked at changes in unit capability and air preheater differential pressures and that he reported increases in capability for other Ameren units where work had been done on air preheaters but no turbine work had occurred. Sind Test., Tr. Vol. 9-B, 22:3-23:17, 25:6-26:2.

290. Mr. Koppe confirmed the increase in capability reported by Ameren to the Public Service Commission was consistent with his review of "thousands of hours of operation at full power." Koppe Test, Tr. Vol. 4-A, at 49:16-23.

291. In its response to the Missouri Public Service Commission, Ameren also reported that a 2.4% efficiency improvement had occurred as a result of the 2010 overhaul, of which 1.9% was due to the LP turbine replacement and 0.5% was due to the reduction in auxiliary load caused by the air preheater and economizer replacements. Dec. 6, 2010 Email re: "Updated DR 0257 Spreadsheet" (Pl. Ex. 216), AM-02757946; Ameren Resp. to DR 0257 (Pl. Ex. 223), at AM-02762954; Sind Test., Tr. Vol. 9-B 26:23-28:3; Finnel Test., Tr. Vol. 10-A, 12:16-13:18. As a result, the increase in capability Ameren reported to the Missouri Public Service Commission was greater than the reported efficiency improvement, which means that Unit 2 would be capable of burning more coal as a result of the 2010 work. Sind Test., Vol. 9-B, 28:6-18; Koppe Test., Vol. 3-B, 52:3-22.

292. Ameren takes its obligation to provide truthful information to the Missouri Public Service Commission seriously. Meiners Rule 30(b)(6) Dep., Oct. 15, 2014, Tr. 19:5-13.

293. Outside of this litigation, Ameren has attributed only 12 MW of the megawatt capacity increase at Unit 2 to the replacement of the LP turbine. Even as recently as a January 2011 email, Mr. Shelton reconfirmed that the 1.9% improvement in efficiency that Ameren reported to the Missouri Public Service Commission equated to 12 MW. Mr. Shelton further stated that while there might be a little more increase, he could not quantify or estimate any such benefit because it would be too uncertain. Shelton Test., Tr. Vol. 10-A, 100:13-101:1, 102:11-103:20; January 21, 2011 Email (Pl. Ex. 935), at AM-02248224.

294. Ameren further raised the capability of Unit 2 after the 2010 boiler upgrade. In December 2010, the gross capacity of Rush Island Unit 2 was further increased to "better reflect the increase in output following the spring 2010 outage in which two new LP turbines were installed and several boiler components were replaced." The July 2011 gross capacity was listed as 641 MW, which was 26 MW greater than the July 2008 capacity, while the December 2011 gross capacity was listed as 653 MW. December 14, 2010 Capability Table (Pl. Ex. 257), at AM-00067232, 67235; Shelton Test., Tr. Vol. 10-A, 92:22-93:15.

295. Mr. Koppe also conducted an analysis of the company's operating data and found a very substantial increase in Unit 2's capability after the 2010 boiler upgrade. Koppe Test., Tr. Vol. 3-B, 5:25-6:3; *id.* at 19:14-19 ("comparing the baseline period to the post-project period, the capability of Unit 2 increased by a large amount"). Mr. Koppe's findings are consistent with Ameren's documents.

296. Mr. Koppe's analysis of the Plant Information ("PI") data focused on those hours in which Unit 2 was operated at "full load," as indicated by the fact that the turbine valves were

wide open, and accepting as much steam as the boiler could produce. Mr. Koppe's approach is consistent with the approach Ameren uses for its full load tests, which are weekly tests done by plant engineers to determine the capability of the units. Koppe Test., Tr. Vol. 3-B, 6:9-7:16, 8:20-9:8; Sind Test., Vol. 9-B, 30:1-7 (during a full load test, the plant is trying to generate as much output as it can).

297. The pre-project period in Mr. Koppe's analysis of the PI data was January 2006 through December 2007, which is the period of time closest to the PSD baseline for which Ameren produced a complete set of data. The capability of Unit 2 during that time was 615 MW. Koppe Test., Tr. Vol. 3-B, 34:2-35:13.

298. The post-project period in Mr. Koppe's analysis of the PI data was October 2010 to August 2011, because that period provided the "best measure … of how much the unit's actual capability had increased" as a result of the project. The post-project capability of Unit 2 was 653 MW (gross). Koppe Test., Tr. Vol. 3-B, 34:16-35:8.

299. Based on the Plant Information data, the overall increase in capability was 38 MW. This is a 6.2% increase in Unit 2's capability. Koppe Test., Vol. 3-B, 49:9-15.

300. Based on his analysis of the PI data, Mr. Koppe determined that 23.3 MW (3.8%) of the increase were related to the component replacements at issue, and 14.7 MW (2.4%) were related to efficiency improvements. The 23.3 MW related to the project at issue resulted in Unit 2 being able to burn more coal per hour. Koppe Test., Vol. 3-B, 34:2-35:13, 49:1-50:18.

301. A similar increase in capability is shown by looking at all of Ameren's full load tests conducted during the PSD baseline period and comparing them to the post-project period. Based on the full load tests, the average capability of Rush Island Unit 2 increased from 620 MW (gross) during the baseline period to 657 MW (gross) during the post-project period, for an

overall increase of 37 MW. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; see also Pl. Ex. 928 (1006 summary of full load tests for Unit 2).

3. Dr. Sahu's emission calculations based on Unit 2's capacity increase

302. As noted above, Dr. Sahu determined that a capability increase of only 1.7 MW at Rush Island Unit 2 will cause a 40 ton per year increase in SO_2 emissions. Sahu Test., Vol. 5, 41:11-14, 46:5-11.

303. Dr. Sahu calculated the emissions associated with an 18-MW increase in capability and determined that Ameren should have expected such an increase to result in an emissions increase of 416.8 tons per year of SO_2. Sahu Test., Vol. 5, 84:5-87:25.

304. The company's project justification documents indicate that it expected Unit 2's capability to increase as a result of the project by more than ten times the amount that would result in 40 additional tons of SO_2 per year. Because the actual and expected increase in capability far exceeded 1.7 MW, and exceeded the 18 MW used in Dr. Sahu's calculations, at least 40 tons of the overall increase in SO_2 emissions are related to the capability increase caused by the replacement of the economizer, reheater, and air preheater at Unit 2. Sahu Test., Tr. Vol. 5, 87:22-25, 97:3-98:16.

4. Nothing in Mr. Caudill's opinions negates Mr. Koppe's calculations of capability increases

305. In contrast with Mr. Koppe, Ameren's capability expert, Mr. Caudill, ignored Ameren's full load tests. He failed to even analyze the performance test that specifically assessed the post-project performance of the boiler upgrades. Although Mr. Caudill reviewed many Ameren performance test reports for turbines, including turbines at plants that are not at issue in this case, he did not review the performance test report for the new reheater, economizer,

and air preheaters that are actually at issue in this case. Caudill Test., Tr. Vol. 10-B, 53:7-54:6; Boiler Performance Test Report (Pl. Ex. 81).

306. Instead, Mr. Caudill simply applied "filters" to the pre- and post-project data that excluded more than 99% of the data in the periods he chose. For instance, the pre-project period he chose included 7,473 hours of data, but he filtered out all but 28 of those hours. Similarly, the post-project period he chose included 14,304 hours, but he filtered out all but 111 hours. Caudill Test., Tr. Vol. 10-B, 67:11-22. The effect of Mr. Caudill's decision to filter out 99% of the operating data was that he only included hours in his capability analysis when the unit was not load limited. Caudill Test., Tr. Vol. 11-A, 4:16-6:4. Rather than assess the actual capability of the Unit 2 boiler, Mr. Caudill excluded all of the effects of pluggage on the boiler's actual capability, including the thousands of hours of data that demonstrated the actual effects of pluggage when the boiler could not produce enough. Koppe Test., Vol. 3-B, 7:17-8:19.

307. Removing Mr. Caudill's filters drastically changes the results of his pre-and post-project comparisons. For instance, at Unit 2, the unfiltered data show that average hourly gross heat input actually increased by over 300 mmBTU per hour and that the maximum hourly gross heat input similarly increased by more than 300 mmBTU per hour. Caudill Test., Tr. Vol. 11-A, 7:10-8:2. Similarly, Mr. Caudill's unfiltered data show that average hourly MW increased by approximately 50 MW and that the maximum hourly megawatts increased by 29 MW. Caudill Test., Tr. Vol. 11-A, 8:3-15 (Caudill Cross Test.).

308. In addition to confirming that Unit 2 was actually operating at higher average hourly heat inputs after the 2010 outage, Mr. Caudill's unfiltered data also confirm that Unit 2 spent significantly more time operating at higher loads following the 2010 outage. For instance, during the pre-project period when Unit 2 was experiencing load limitations due to pluggage, it

spent only 10% of its operating hours at the highest load range identified by Mr. Caudill, with the largest fraction of the operating hours (40%) spent at the second highest load range. By contrast, after the 2010 outage the load range at which Unit 2 operated the most had shifted up to the highest load range identified by Mr. Caudill, with Unit 2 spending 40% of its operating hours at the highest load range after the 2010 outage as compared to 10% before the outage. Caudill Test., Tr. Vol. 11-A, 11:8-13:16. This is exactly what would be expected when a plugged boiler is no longer load limited following an upgrade.

309. Mr. Caudill also expressed an opinion on efficiency. However, his efficiency analysis suffered from at least two fundamental flaws that render it of little to no relevance here. First, Mr. Caudill conceded that his opinions do not address whether the projects were expected to, or did, cause increases in the total annual amount of generation or fuel burned at Rush Island. By analogy, Mr. Caudill explained that his analysis looked at the equivalent of miles-per-gallon rather than looking at the total gallons of fuel used in a year. Caudill Test., Tr. Vol 10-B, 11:20-12:12.

310. Second, Mr. Caudill did not analyze the required NSR pre-and post-project periods. Ameren itself has chosen specific two-year pre-project baseline periods to present in this case for purposes of determining whether its projects violated New Source Review. Vol. 10-B, 30:19-31:12 (Caudill Cross Test.). Yet Mr. Caudill only used approximately one year of pre-project data. And at Unit 2 there was not a single month in the pre-project period that Mr. Caudill used that actually overlapped with the two-year NSR baseline period that is at issue in this case. Caudill Test., Tr. Vol. 10-B, 32:4-33:17.

311. In addition, the time periods Mr. Caudill examined skew his results. For instance, he relied on pre-project periods when efficiency was significantly worse than it was during the

applicable NSR baseline period, effectively making the unit less efficient for purposes of his comparison. Ameren's Exhibit TW demonstrates that during the pre-project period selected by Mr. Caudill, Rush Island Unit 2 had the worst efficiency (i.e., the highest heat rate) in any of the five years leading up to the 2010 outage. Yet Mr. Caudill did not even look at data from those other years. Exhibit TW; Caudill Test., Tr. Vol. 10-B, 42:25-43:19.

D. PROSYM-BASED EMISSIONS CALCULATIONS

312. In addition to Dr. Sahu's translation of the performance improvements calculated by Mr. Koppe into calculations of emissions increases, the United States also presented emissions analyses performed by Dr. Ezra Hausman using Ameren's production cost modeling program.

313. Ameren's experts agree that using results from a production cost modeling run is an appropriate way to forecast future emissions for a New Source Review analysis. King Test., Tr. Vol. 6-B, 66:3-15; Chupka Test., Tr. Vol. 8-B, 80:14-17. In fact, Ameren expert Michael King admitted that he used production cost modeling runs in his New Source Review analyses in prior enforcement cases. King Test., Tr. Vol. 6-B, 66:16-19.

1. Production cost modeling at Ameren

314. "A production cost model is a computer application used to simulate an electric utility's generation system and load obligations." Finnell MPSC Test. (Pl. Ex. 439), at 3:10–11.

315. Ameren regularly uses a production cost model called ProSym to forecast its unit operations for a variety of business purposes, including fuel budgeting and rate case justifications before the Missouri Public Service Commission. Finnell MPSC Test. (Pl. Ex. 439), at 3:11–14; Ringelstetter Test., Vol. 11-B, 12:15–17.

316. Ameren's ProSym model is calibrated with actual load information to check its accuracy as a forecasting tool. Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-20. The calibration shows that the projection runs "come within a fairly high degree of accuracy." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-29:13. According to Ameren, ProSym "does a good job of modeling the electric system and how it's operated." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 29:2-13.

317. This computer simulation software uses a complex algorithm, but is basically a "supply and demand" model that predicts how the system operator, MISO, will dispatch Ameren's units hour-by-hour for a given period after taking into account various inputs like unit performance projections and load forecasts that Ameren develops as inputs into the program. Finnell Test., Tr. Vol. 9-B, 67:10–11; Hausman Test., Tr. Vol. 4-B, 41:17–23, 44:7–15.

318. As Ameren's witness Mr. Finnell explained, at Ameren, "[t]he fuel budget process involves collecting information from various work groups or [expert] areas in the company for items that are used in the ProSym model. The ProSym model is then executed, and the results are prepared and issued to various groups within the company." Finnell Test., Tr. Vol. 9-B, 66:22–67:1.

319. The fuel budgeting process typically involves forecasting unit operations for five years. Finnell Test., Tr. Vol. 9-B, 70:20- 21.

320. Ameren's modeling runs show how unit performance improvements interact with rising system loads or other market factors to affect unit operations. Hausman Test., Tr. Vol. 4-B, 40:7–12; Ringelstetter Test., Tr. Vol. 11-B, 56:10-21.

321. Jaime Haro, Ameren's manager in charge of load forecasting and risk management, testified at trial he had worked with the company's modeling department, and

confirmed that Ameren's modeling resources could be used to perform sensitivity analyses and investigate how different scenarios might impact operations at Ameren's units. Haro Test., Tr. Vol. 9-A, 133:1–14.

322. The inputs used by ProSym in simulating dispatch and operations can be divided into two types: market factors and unit characteristics. Hausman Test., Tr. Vol. 4-B, 42:13–17.

323. Market considerations that are input into ProSym include things like hourly load data—e.g., load forecasts for the market Ameren serves—as well as fuel costs, off-system market data, and system requirements. Finnell MPSC Test. (Pl. Ex. 439), at 3:3–5; Hausman Test., Tr. Vol. 4-B, 42:21–43:15.

324. Unit characteristics that are supplied for the model include measures of the unit's efficiency (also called its "heat rate" as it describes how much heat or fuel it takes for the unit to produce each unit of electricity), the unit's maximum capacity, the unit's projected availability, and other physical constraints such as how long it takes the unit to ramp up to full load if it is taken offline for any reason (its "ramping constraints"). Hausman Test., Tr. Vol. 4-B, 43:21–44:3.

325. As used by Ameren, the model takes into account two measures of unit availability when it projects unit operations: a unit's "forced outage rate," and its "partial outage rate." Hausman Test., Tr. Vol. 4-B, 52:25–53:20.

326. The forced outage rate is a measure of time that the unit was able to run at any level. So, in a non-leap year, it would be the number of hours the unit could run divided by 8,760, the number of hours in a year. Hausman Test., Tr. Vol. 4-B, 53:2–6.

327. The partial outage rate is the model's input for deratings. It is the percentage of actual available generation divided by the total available generation from the unit assuming

every available hour could have been loaded at full power. Hausman Test., Tr. Vol. 4-B, 53:9–15.

328. Adding the forced and partial outage rates of a unit together gives you the "effective unit outage rate." To determine a unit's equivalent availability factor, one subtracts the effective unit outage rate from 1. Hausman Test., Tr. Vol. 4-B, 53:16–54:9.

2. Dr. Hausman's sensitivity analyses

329. After investigating Ameren's modeling files, Dr. Hausman identified several performance improvements that Ameren modeled at its Rush Island plants concurrent with the boiler upgrade work at issue in this case. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

330. Dr. Hausman executed "sensitivity analyses" using Ameren's production cost modeling files to determine how the performance improvements at the Rush Island Units were impacting the modeling projections for those units' operations. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

331. A sensitivity test is a standard modeling technique whereby a modeler runs a computer simulation multiple times, varying only one input or parameter a little bit each time in order to investigate how that single element interacts with the rest of the system being modeled. Hausman Test., Tr. Vol. 4-B 46:24–47:8.

332. Dr. Hausman's sensitivity analyses revealed straightforward, linear relationships between unit capacity or unit availability and the unit's projected fuel use—and, accordingly, pollution levels. Hausman Test., Tr. Vol. 4-B, 55:20-56:19, 63:20-64:20, 65:22-66:7, 71:7-25, 72:12-21.

333. As shown below, any one of the performance improvements that Ameren modeled at the Rush Island units following the boiler upgrades would result in a concomitant

increase in fuel use that would translate into a pollution increase well above the 40 tons-per-year threshold for SO_2 to trigger New Source Review. Hausman Test., Tr. Vol. 4-B, 73:11–21.

a. Unit 1 sensitivity analysis

334. For Unit 1, Dr. Hausman reviewed a credible fuel budgeting modeling run performed in 2006 in order to evaluate how performance improvements following the 2007 projects at Unit 1 would be projected to affect operations and pollution. The model run he used was contemporaneously performed by the company when Ameren was planning the Unit 1 work, the modeling files were complete (allowing for replication and verification of the results), and the inputs presented credible, long-term forecasts without "red flags" such as artificial constraints or other indications that would suggest the model run was used for a different purpose or did not reasonably reflect company expectations. Hausman Test., Tr. Vol. 4-B, 68:4-16 & 97:15–98:1; *see also* Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling).

335. Comparing the year before the work was performed to the year after it was completed, Ameren modeled a 4% increase in equivalent availability following the boiler upgrades—a 2.2% improvement in the unit's forced outage rate and a 1.8% improvement in the unit's partial outage rate. Hausman Test., Tr. Vol. 4-B, 69:16–22.

336. Dr. Hausman determined that a one percentage point improvement in Unit 1's forced outage rate would translate into an additional 481 billion BTUs of fuel consumption per year and an additional 162 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 71:19-23.

337. Dr. Hausman also found that reducing Unit 1's partial outage rate (deratings) by one percentage point would result in an additional 408 billion BTUs of fuel consumption per year and an additional 138 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 72:12–21.

b. Unit 2 sensitivity analysis

338. For Unit 2, Dr. Hausman reviewed Ameren's "Original" 2010 Fuel Budget modeling run performed in early 2010 in order to evaluate how performance improvements following the 2010 projects at Unit 2 would be projected to affect operations and pollution following that work. That model run was used by Ameren's environmental services department to perform its "reasonable possibility analysis" for that work. Hausman Test., Tr. Vol. 4B, 49:6–10; Hutcheson Test., Vol. 11-A, 38:22-39:1.

339. Dr. Hausman determined that each additional megawatt of increased unit capacity at Unit 2 will result in that unit burning an additional 69 billion BTUs per year and an additional 23 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 59:24–60:2.

340. Dr. Hausman also found that a one percentage point improvement in the unit's forced outage rate would translate into an additional 566 billion BTUs per year and, as a result, an additional 189 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

341. A one percentage point improvement in Unit 2's partial outage rate would translate into an additional 466 billion BTUs per year and, as a result, an additional 156 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

3. Dr. Hausman's "with and without" analyses

342. In addition to his sensitivity analyses, Dr. Hausman also performed a "with and without" analysis using Ameren's ProSym model. A "with and without" analysis is a standard modeling technique used throughout the industry and in many fields that employ computer modeling. It compares two scenarios—one in which the performance improvements Ameren expected were realized (the scenario Ameren itself modeled), and another scenario in which the

units simply continued operating as they had in the past, without realizing any performance improvements as a result of the modifications. Hausman Test., Tr. Vol. 4-B, 25:12–18, 74:5–7.

343. This technique allows the modeler to look at the impact of one change (or set of changes) in the system while holding all else constant. Hausman Test., Tr. Vol. 4-B, 25:16–19 & 74:7–12.

344. Ameren's experts conceded that utilities often run a production cost model twice, changing just one variable, in order to see how changing that variable would impact the output of the model. King Test., Tr. Vol. 6-B, 67:14-19; Chupka Test., Vol. 8-B, 79:18-81:2. As Ameren expert Marc Chupka testified, the type of with-and-without modeling analysis that Dr. Hausman did in this case is a "standard tool" in utility modeling practice. Chupka Test., Tr. Vol. 8-B, 80:18-22.

345. Ameren expert Michael King agreed that the difference between two estimates of future emissions – one of which accounted for the project and one of which did not – would show the impact of the project. King Test. Tr. Vol. 6-B 69:7-71:23.

346. In his testimony in a prior NSR enforcement case, Ameren expert Michael King performed two modeling runs to identify the emissions that he testified were unrelated to the project and should be excluded from an NSR calculation under the demand growth exclusion. King Test. Tr. Vol. 6-B 65:17-21. In other words, Mr. King used the same technique in that case that Dr. Hausman did here (except Mr. King set out to identify the emissions that were *unrelated* to the project, while Dr. Hausman identified the emissions *related* to the project).

347. Similarly, Ameren expert Marc Chupka testified that one way to perform an NSR emissions analysis would be to (1) start with a contemporaneous emissions projection that

incorporates the effect of the project; (2) compare that projection to the baseline period; and then (3) address any unrelated factors. Chupka Test., Tr. Vol. 8-B, 81:3-24.

a. Unit 1 analysis

348. For Unit 1, Dr. Hausman's with-and-without analysis compared the ProSym modeling forecasts performed by Ameren in 2006 to another version in which the unit did not increase its availability by 4% following the work.

349. The comparison revealed that, but for the performance improvements modeled at the unit, Rush Island Unit 1 would have operated 192 fewer hours, the unit would have burned over 1,600 billion BTUs less coal, and it would have emitted 562 fewer tons in the year he examined. Hausman Test., Tr. Vol. 4-B, 79:23–80:7.

350. Based on Ameren's updated 2006 fuel budget modeling, the company projected that it would emit as much as 15,561 tons per year of SO_2 in the five years after the project, a 687-ton increase above baseline levels. Of that projected increase in emissions, 562 tons would not have been projected were it not for the availability improvements modeled at Unit 1. Hausman Test., Tr. Vol. 4-B, 80:10–21.

351. Dr. Hausman also used Ameren's Plant Information data to develop inputs based on the putative performance improvements in the company's Plant Information data. Dr. Hausman accepted the data at face value and gave Ameren credit for a 3.0% efficiency improvement (more than Ameren reasonably should have or did expect) and also incorporated a 20-MW increase in Unit 1's capacity. Hausman Test., Tr. Vol. 4-B, 81:1–3.

352. Using these inputs from the company's Plant Information data and re-running his with-and-without analysis, Dr. Hausman found that Ameren would have projected a 716-ton

increase above baseline pollution levels, of which 591 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 81:3–6.

b. Unit 2 analysis

353. For Unit 2, Dr. Hausman compared the ProSym modeling forecasts performed by Ameren to another version in which the unit did not increase its capacity by 18 MW and improve its availability by 2% following the work. The performance improvements represented by Ameren in this model are consistent with the performance improvements that Mr. Koppe independently determined the company should have expected to result from the boiler work. Hausman Test., Tr. Vol. 4-B, 82:21–24. The comparison revealed that, without the performance improvements modeled at the unit, Rush Island Unit 2 would have operated 96 fewer hours, the unit would have burned nearly 1,600 billion BTUs less in coal, and it would have emitted 746 fewer tons of SO_2 in the year he examined. Hausman Test., Tr. Vol. 4-B, 75:18–76:5.

354. Based on Ameren's "original" 2010 fuel budget modeling, the company projected as much as 16,816 tons per year of SO_2 in the five years after the project, a 2,528-ton increase above baseline levels. Of that projected increase in emissions, 746 tons would not have been projected were it not for the performance enhancements modeled at Unit 2. Hausman Test., Tr. Vol. 4-B, 76:22–77:6.

355. As with Unit 1, Dr. Hausman reviewed Ameren's Plant Information data to develop inputs based on the putative performance improvements contained in the company's data. Once again, Dr. Hausman accepted the Plant Information data at face value. Thus, Dr. Hausman gave Ameren credit for an efficiency improvement (4.2%) that exceeded what it reasonably should have or did expect, and also incorporated a 34 MW increase in capacity (a 5.75% increase). Hausman Test., Vol. 4-B, 79:6–8.

356. Using these PI-inputs and re-running his with-and-without analysis, Dr. Hausman concluded that Ameren still would have projected a 1,905-ton per year increase above baseline pollution levels, of which 696 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 78:21–79:2.

IV. AMEREN HAS FAILED TO MEET ITS BURDEN TO ESTABLISH THE APPLICABILITY OF THE DEMAND GROWTH EXCLUSION

357. Ameren pled as its Twenty-Sixth Affirmative Defense that any emissions increases following the 2007 and 2010 outages at Rush Island Unit 1 or Unit 2 were the result of increased demand and not the projects at issue. Answer (ECF No. 250), at 31.

A. Background about the Market for Rush Island's Generation

358. The Midcontinent Independent System Operator ("MISO") serves as the dispatch operator for Ameren's Rush Island units. Hausman Test., Tr. Vol. 4-B, 33:24–34:1.

359. As a dispatch operator, MISO aims to meet system demand with the lowest-cost—though still reliable—portfolio of electricity generation it can. "[G]eneration owners tell the dispatch operator what's available and at what price. And then the dispatch operator uses a computer algorithm to find the lowest cost way of meeting load." Hausman Test., Tr. Vol. 4-B, 33:19–23, 34:2–9.

360. "MISO's job is to find the lowest cost way of meeting that demand. And the way they do that is they start by turning on the lowest cost sources of energy first. Those are often nuclear or coal units like the Rush Island units. And then they progressively turn on more and more costly generators to run until at every moment the energy being generated is balanced with the load required by the system." Hausman Test., Tr. Vol. 4-B, 31:14–21.

361. As a general matter, electricity cannot be stored, so—at least when considering the system as a whole—electricity production and demand must be constantly balanced. Hamal Test., Tr. Vol. 9-A, 98:11–13. That does not mean, though, that electricity production and demand are the same thing. As with every market, the electricity market has a demand side and a supply side—and just because demand for electricity may be rising does not mean that any specific generating unit will be used to serve that rising demand. Hamal Test., Tr. Vol. 9-A 41:24–42:8.

362. The Rush Island units cannot generate—and so cannot serve demand—if they are unavailable. And Ameren cannot offer generation it does not have to the market: if a Rush Island unit was forced offline because of some mechanical failure, Ameren would not be able to offer Rush Island generation into the MISO market. Similarly, when Rush Island units are load limited or derated for some reason, Ameren cannot offer the unavailable portion of its generating capacity to the MISO market. Hamal Test., Tr. Vol. 9-A, 40:21–41:7; Naslund Test., Tr. Vol. 6-B, 13:24-14:5; King Test., Tr. Vol. 6-B, 52:24-53:6 (demand and availability are both necessary in order for a unit to operate).

363. Furthermore, in general, MISO cannot call on Ameren's units to provide more electricity than Ameren has offered into the market. Hamal Test., Tr. Vol. 9-A, 41:10–14; Hausman Test., Tr. Vol. 4-B, 35:6–9.

364. Ameren does not need MISO's permission to bring a unit offline if it has experienced a tube leak or other failure at the unit. Hamal Test., Tr. Vol. 9-A, 41:17–20; Hausman Test., Tr. Vol. 4-B, 35:10–12.

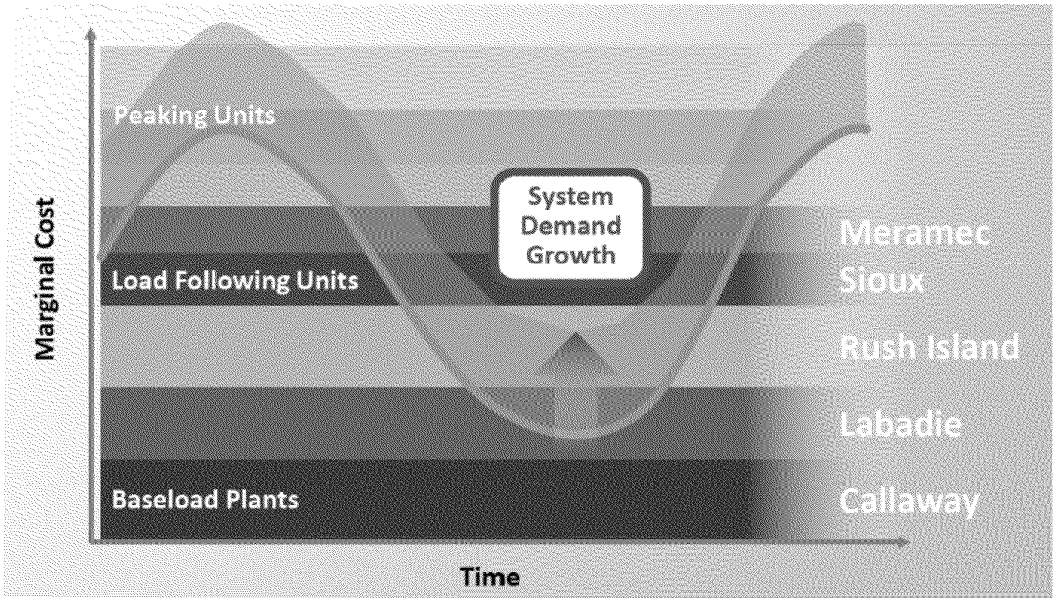
365. MISO does not tell generation owners like Ameren how to spend their capital improvement budgets or how to improve their generation services. Hamal Test., Tr. Vol. 9-A,

41:21–23; Hausman, Tr. Vol. 4-B, 35:13–19; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. Ameren controls the engineering of its units and decides what maintenance work needs to be performed and when to perform that work. Hausman Test., Tr. Vol. 4-B, 36:3–6; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. By controlling the maintenance of and investment in the Rush Island generating units, Ameren manages those supply assets to ensure that they can serve as much market demand as they can. Hausman Test., Vol. 4-B, 35:23–36:21.

366. MISO does not pay bonuses to generation owners when their units perform well or reliably. Hausman Test., Tr. Vol. 4-B, 35:20–22.

367. "Rush Island has low operating cost[s]. MISO's job is to run the system as efficiently as possible, and that translates into MISO doing what it can to get Rush Island to run more." Hamal Test., Tr. Vol. 9-A, 37:20–23. As a natural corollary, if Ameren is able to make the Rush Island units able to operate more hours or at higher loads, then MISO would call on them to make use of that new-found capability. Hamal Test., Tr. Vol. 9-A, 51:22–52:17.

368. Jaime Haro, Senior Director of the Ameren's Enterprise and Commodity Risk Management Department, described how the Rush Island units compare to other units in Ameren's generating portfolio by providing a generalized schematic of the "merit order" or "dispatch order" of its various plants. Haro Test., Tr. Vol. 9-A, 130:14 – 132:9; Hausman Test., Tr. Vol. 4-B, 31:14–32:22. At the bottom of the schematic are units that cannot shut down and are the cheapest to run, such as Ameren's Callaway nuclear plant. Next up to be dispatched are other baseload coal units such as the Rush Island generating units that run basically whenever they are available. Haro Test, Vol. 9-A, 65:1–66:1; Tr. Vol. 6-A, 55:4-7.



[Ameren Demonstrative WC_2]

369. Coal units like Rush Island are expensive to shut down, and it takes hours—sometimes as much as a day—to start them back up. Hamal Test., Tr. Vol. 9-A, 45:10–15. As such, the Rush Island units may ramp down their generation through the night or during other periods of low system load, but they generally do not turn off. Hamal Test., Tr. Vol. 9-A, 46:7–23; Haro Test., Tr. Vol. 9-A, 131:7–12.

370. As illustrated by Ameren's schematic, the general impact of an increase in system demand is that the Rush Island units might ramp down a little later at night than they otherwise would, or ramp up to high loads a little earlier in the mornings than they otherwise would. Haro Test., Tr. Vol. 132:2–9.

371. As Mr. Haro testified, though, when load is up, as it often is during the "on peak" hours shown with relatively high prices at the left and right hand side of the graphic, the Rush Island units are typically generating as much as they can. Haro Test., Tr. Vol. 9-A, 131:1–15.

Obviously, if the unit is already fully loaded, it cannot increase its output in order to serve more of the market's demand for electricity. Hamal Test., Vol. 9-A, 58:16–17.

372. In general, the Rush Island units are more likely to be running fully-loaded during "on peak" hours than "off peak" hours. Hamal Test., Tr. Vol. 9-A, 59:3–5, 59:17–19. Even according to Ameren's expert's analysis, only a third of the hours the Rush Island Unit 2 operated with some available capacity to spare were "on peak" hours. Thus, according to Ameren's expert, Unit 2 was at maximum capacity for more than half of all hours in the baseline period—and more than two-thirds of all "on peak" hours in the baseline period. Ringelstetter Test., Vol. 11-B, 40:10 – 15; Def. Demonstrative TK-15.[3]

373. This relationship is borne out in Ameren's modeling files. For example, as is evident in Ameren's modeling efforts performed in 2006, even when the company forecast system load to increase each year, the Rush Island units were projected to generate at essentially flat levels throughout the forecast period. As Dr. Hausman explained, this clearly indicates the Rush Island Units are baseload units, and they are more or less insensitive to variations in system load. Hausman Test., Tr. Vol. 4-B, 45:20–22.

B. Ameren's Failure of Proof Regarding Demand Growth as a Cause of Increased Emissions

374. In the company's 2011 Corporate Social Responsibility Report, Ameren characterized the projects at issue in this case as "necessary to respond" to increased demand. Naslund Test., Tr. Vol. 6-B, 16:12-15, 18:3-5; Corporate Social Responsibility Report (Pl. Ex.

---

[3] Even this number appears to understate how often the units were run at their "available capacity." Ms. Ringelstetter's analysis does not accurately reflect those hours when the unit was ramping up after coming offline. She counted those hours as having "available capacity" even though the units would have been physically incapable of generating more during that time. Ringelstetter Test., Vol. 11-B, 69:3–70:15.

431) at AM-00510618. In other words, Rush Island could not have served at least some of the increasing system demand *without* the Rush Island upgrade projects.

375. To the extent that system demand was growing, as of 2008, Ameren expected that its purchase of three combustion turbines (natural gas units), would satisfy that demand growth until at least 2018. Naslund Test., Tr. Vol. 6-B, 15:14-16:11.

376. To the extent that system demand was growing, Ameren did not offer any evidence at trial to show how changes in system demand, if any, would or did specifically impact the operation of and emissions from the Rush Island units. For example, Ameren utility market expert Cliff Hamal admitted that he did not quantify "how demand would change Rush Island's operations in any way." Hamal Test., Tr. Vol. 9-A, 39:23–40:5.

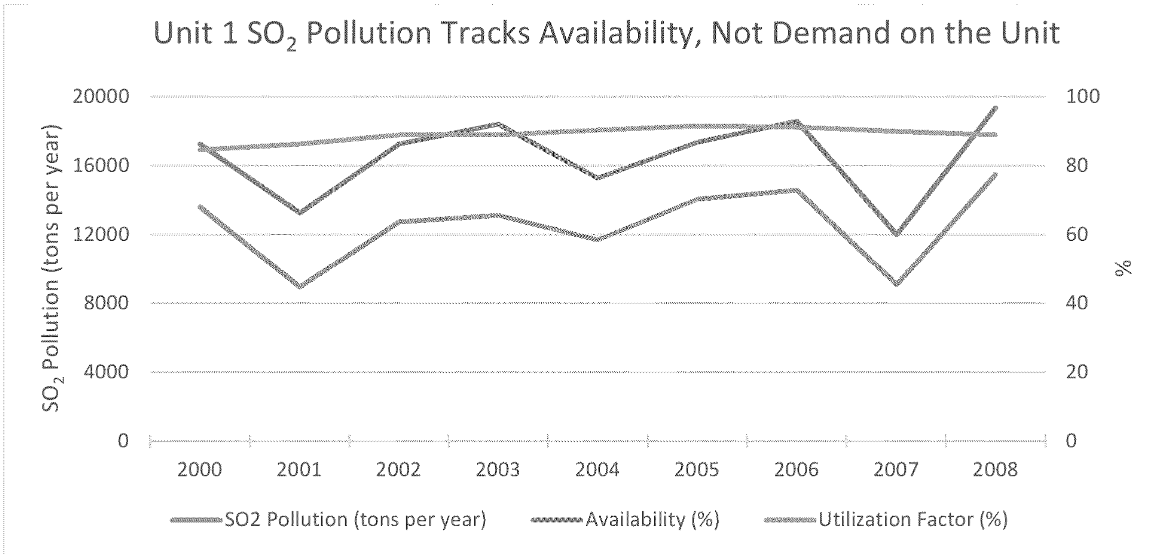
377. The industry does have a standard measure that isolates demand for the output of individual generating units. That metric is known as the "utilization factor," and Ameren itself uses it during the course of its business. Sahu Test., Tr. Vol. 5, 56:18-57:3, 76:15-22; Ringelstetter Test., Tr. Vol. 11-B, 80:18-81:6; Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011-12 ("loading order [is] reflected in the utilization factor") (EPRI Report, Vol. 1); Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions" (utilization factor is the "percent of mwhrs used after outages and derates").

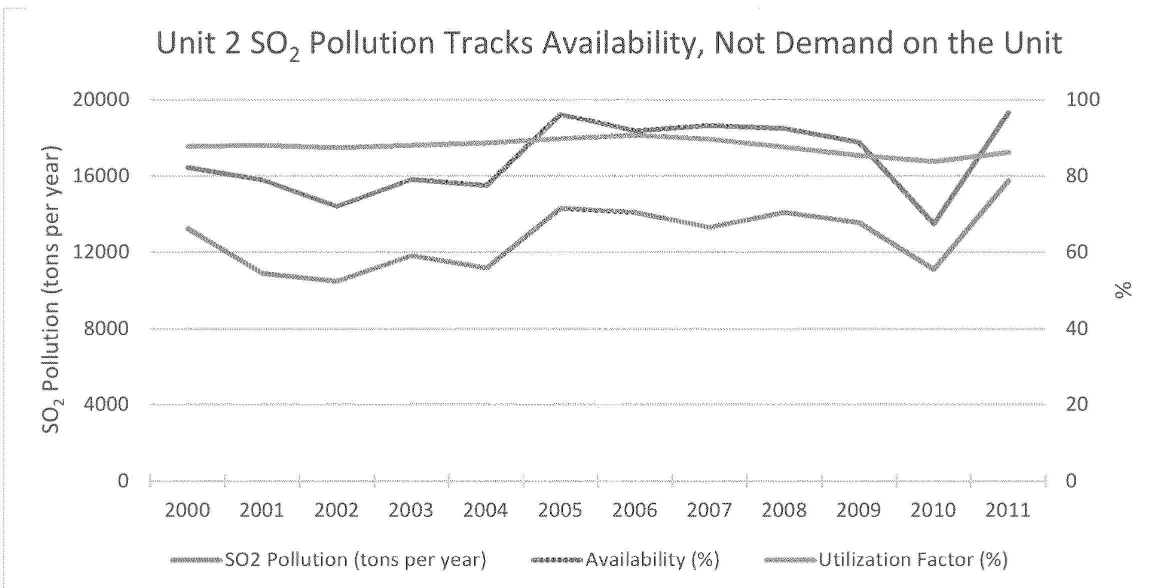
378. Ameren expert Michael King testified that demand for the generation of coal units had been decreasing since 2007 due to falling natural gas prices. King Test., Tr. Vol. 6-B, 34:20-35:3, 35:8-16. Mr. King also testified that the utilization factors for the Rush Island units have been declining since around 2007. King Test., Tr. Vol. 6-B, 87:13-24. Mr. King further explained that if the utilization factor is decreasing, any emissions increases during that time period cannot be the result of increased demand. King Test., Tr. Vol. 6-B, 88:3-6, 89:9-12.

379. Ameren expert Sandra Ringelstetter calculated utilization factors in this case and found that the utilization factor for Unit 1 was projected to remain basically constant and in fact decreased from 91.18% in the baseline period to 89.66% in the applicable post-project period. Ringelstetter Test., Tr. Vol. 11-B, 83:4–15; Def. Ex. NE, at "RI U1 2007 Summary" tab. As a result, any increase in generation that was projected to occur and was in fact realized at Unit 1 following the 2007 outage cannot be attributed to increased demand.

380. For Unit 2, Ms. Ringelstetter calculated that Unit 2's utilization was projected to increase slightly (about 2%), but that it in fact decreased from 91.45 in the baseline period to 89.37 in the relevant post-project period. Ringelstetter Test., Tr. Vol. 11-B 81:7-83:3; Def. Ex. NE, at "RI U2 2010 Summary" tab. As a result, the more than 15% increase in emissions that was projected to occur and that was in fact realized at Unit 2 following the 2010 boiler upgrades cannot be attributed to increased demand.

381. At Rush Island, emissions of SO_2 track availability of the units more closely than demand. Sahu Test., Tr. Vol. 5, 103:5-107:19; *see also* King Test., Tr. Vol. 6-B, 86:2-23 (Ameren expert conceding the relationship between availability and SO_2 pollution at Rush Island).





382. Ameren did not offer any evidence to explain how an increase in emissions associated with an increase in capacity at Rush Island can be caused by demand growth.

V. AMEREN'S NSR EMISSION ANALYSES

383. Ameren called two witnesses at trial from its Environmental Services Department: Steven Whitworth and Michael Hutcheson. Mr. Whitworth was the Supervisor of the Air

Quality section within Ameren's Environmental Services Department from 2002 to 2007. In 2007, Mr. Whitworth became Department manager, which meant that he has ultimate responsibility over the entire Environmental Services group. Whitworth Test., Tr. Vol. 11-A, 90:4-9. Mr. Hutcheson works for Mr. Whitworth and was the Ameren employee responsible for performing the NSR emissions calculations that Ameren presented at trial. Hutcheson Test., Tr. Vol. 11-A, 34:2-35:2, 54:20-55:11, 63:9-15.

384. Ameren does not have any internal guidelines for performing a New Source Review analysis. Hutcheson Test, Tr. Vol. 11-A, 65:21-24.

385. The Environmental Services Department at Ameren is responsible for determining New Source Review applicability. Environmental Services does not have any role in Ameren's capital project justification process. Naslund Test., Tr. Vol. 6-B, 19:20-23, 20:7-18.

386. Project justification packages include a document called the Project Risk Management Plan. Schweppe Dep., May 20, 2014, Tr. 112:2-7.

387. Robert Schweppe was Director and later Managing Supervisor of the Project Engineering group at Ameren. Prefatory Statement to Depo Designation, Vol. 6-A, 19:9-11; Project Approval Package (Pl. Ex. 1), at AM-0072586. Mr. Schweppe signed off on the Project Risk Management Plan for the major component replacements at issue for both Unit 1 and Unit 2. Project Approval Package (Pl. Ex. 1), at AM-00072606 (Unit 1 boiler components); Project Approval Package (Pl. Ex. 3), at AM-00072841 (Unit 2 boiler components); Project Approval Package (Pl. Ex. 4), at AM-00072864 (Unit 1 air preheater); Project Approval Package (Pl. Ex. 6), at AM-00072923 (Unit 2 air preheater).

388. Each Project Risk Management Plan lists whether certain risk factors have been addressed, followed by a series of check boxes. One of the check boxes is for

"Legal/Environmental." For each of the projects at issue, the Legal/Environmental box was not checked. Pl. Ex. 1 at AM-00072606; Pl. Ex. 3 at AM-00072841; Pl. Ex. 4 at AM-00072864; Pl. Ex. 6 at AM-00072923.

389. Mr. Schweppe testified that he did not know why the Legal/Environmental box was not checked, and that he did not "recall that box ever being checked" for "any project risk plan." Mr. Schweppe continued that he did not know what the box meant and that he had never asked anyone to understand what it meant. Schweppe Dep., May 20, 2014 Tr., 112:14-114:5.

A. Ameren Performed No Pre-Project NSR Analysis for Either Project

1. Rush Island Unit 1

390. Ameren has admitted that it performed no emission calculations for purposes of determining PSD applicability prior to undertaking the 2007 project at Unit 1. Whitworth Test., Tr. Vol. 11-A, 94:23-25; Boll Test., Tr. Vol. 8-B, 38:3-5; Birk Dep., Sept. 24, 2013, Tr. 220:14-21; *see also* Knodel Test., Tr. Vol. 1-A, 88:10-12; Ameren Closing Arg., Vol. 12, 51:18-20.

391. Mr. Whitworth, the Head of Ameren's Environmental Services department, testified at trial that the only pre-project emission evaluation he did for Unit 1 was a non-numerical analysis that considered only whether the Unit 1 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19; *see also* Boll Test., Tr. Vol. 8-B, 9:7-13:25 (company relied on non-numerical evaluation of whether project would have an impact on maximum continuous rating), 38:3-14.

392. Ameren's Environmental Services Department did not communicate with project engineer David Boll at any time prior to the Unit 1 project completion in 2007. Boll Test., Vol. 8-B, 39:17-21, 40:6-9.

393. The Rush Island Plant Manager at the time of the 2007 outage was Robert Meiners. As plant manager, he was accountable for making sure the plant complied with environmental regulations. Meiners Test., Tr. Vol. 7-B, 64:2-5. However, Mr. Meiners had no communications with anyone about whether to seek a New Source Review permit for the Unit 1 project. When asked whether he understands that PSD requires utilit[ies] to make a prediction of future emissions in order to do [] emissions analys[es], Mr. Meiners replied "That's not – not my responsibility. I'm not involved with it." Meiners Dep., April 8, 2014, Tr. 342:11-17. In fact, Mr. Meiners testified that throughout his more than 40-year career at Ameren, he never had a single discussion with anyone about whether or not to seek an NSR permit for any capital project at all. Meiners Test., Tr. Vol. 7-A, 68:2-18 and Vol. 7-B, 64:2-20. Similarly, Mr. Strubberg testified that he was not involved in any assessment of whether the projects triggered PSD. Strubberg Test., Tr. Vol. 8-A, 73:17-74:5.

394. Prior to undertaking the Unit 1 project, Ameren did not communicate with permitting authorities about whether a New Source Review permit would be required. Whitworth Test., Tr. Vol. 11-A, 106:3-7.

2. Rush Island Unit 2

395. The Head of Ameren's Environmental Services department, Mr. Whitworth, testified at trial that the only pre-project emission evaluation he did for Unit 2 was a non-numerical analysis that considered only whether the Unit 2 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19.

396. The Ameren employee who was responsible for doing NSR calculations for Unit 2 was Michael Hutcheson. Mr. Hutcheson testified that he did not review any EPA or

Missouri Department of Natural Resources guidance specifically as part of his work for the project at issue. Hutcheson Test., Tr. Vol. 11-A, 65:25-66:2.

397. Mr. Hutcheson admitted he had no personal knowledge of the project or whether the effects of the project were included in the projections he relied upon.

a. Mr. Hutcheson testified that in performing the company's NSR analysis, he did not speak to any of the engineers who planned and developed the project. He received information from his superiors in the Environmental Services Department, but he did not know the source of that information. Hutcheson Test., Tr. Vol. 11-A, 63:5-19.

b. Mr. Hutcheson also testified that he did not review any of the project justification documents for the work. Hutcheson Test., Tr. Vol. 11-A 63:20-25.

c. Mr. Hutcheson did not know whether the modeling runs that he relied on for his analysis included any projected improvements in capacity or availability. Mr. Hutcheson did nothing to check the validity of the modeling runs he received, but simply "took them on their face." Hutcheson Test., Tr. Vol. 11-A, 65:4-20; Hutcheson Dep., April 24, 2014, Tr. 118:20-119:5.

d. Mr. Hutcheson testified that he did not consider whether availability was expected to improve as a result of the projects because he did not think that information was "relevant" or "necessary." Hutcheson Test., Tr. Vol. 11-A, 82:16-25.

398. Mr. Hutcheson performed two purported NSR analyses for the Rush Island Unit 2 project – the "Original" Reasonable Possibility Analysis and the "Amended" Reasonable Possibility Analysis. Neither analysis was completed before the project work started. Knodel Test., Tr. Vol. 1-A, 88:13-18; Whitworth Test., Tr. Vol. 11-A, 96:12-23, 97:2-15; Hutcheson

Test., Tr. Vol. 11-A, 84:15-17, 85:3-8. Mr. Hutcheson's analysis relied on a ProSym model run the company performed that had been completed in January 2010, after the outage had begun. Hutcheson Test., Vol. 11-A, 38:22-24. The Original Reasonable Possibility analysis was not completed until after the project had begun. Mr. Hutcheson admitted that the analysis *should* be completed before beginning construction. Hutcheson Test., Tr. Vol. 11-A, 56:1-7; 84:15-85:2; *see also* Knodel Test., Tr. Vol. 1-A, 88:24-89:3.

399. Mr. Hutcheson began working on the Original Reasonable Possibility Analysis only after Ameren's legal department requested analyses of about 20 projects, including the Rush Island Unit 2 project. Some of the projects he was asked to analyze had already occurred and some were planned for the future. Hutcheson Test., Tr. Vol. 11-A, 34:2-23.

400. Although the Unit 2 project was originally approved in 2005 and re-approved by Ameren's Board of Directors and CEO on August 14, 2009 (FOF 136, 137), Mr. Hutcheson did not even begin collecting information relevant to his NSR analysis until November or December 2009. Hutcheson Test., Tr. Vol. 11-A, 84:11-14.

401. Ameren's "Original" ProSym modeling run was not completed until January 2010, after the 2010 outage had begun. The original case was used to develop the corporate budget for 2010. Finnell Dep., Nov. 22, 2013, Tr. 79:2-8. After the 2010 outage was complete, Ameren ran two other modeling cases, including the "EDF" case. Finnell Test., Tr. Vol. 10-A, 9:25-10:5. The EDF case was completed in early 2011. Finnell Test., Tr. Vol. 10-A, 10:3-5. The EDF case was the same as the "Original" case, but was modified to include efficiency improvements. Finnell Dep., Nov. 22, 2013, Tr. 77:12-20. The EDF case was used by environmental services to perform the Amended Reasonable Possibility Analysis. Finnell Dep., Nov. 22, 2013, Tr. 76:4-79:8; Hausman Test., Tr. Vol. 4-B, 87:11-14.

402. Ameren's Original Reasonable Possibility analysis "projected" that Unit 2's emissions of SO_2 would increase by 2,531.15 tons per year, from 14,287.73 in the baseline period to 16,818.88 tons per year in the highest projected post-project period. Hutcheson Test., Tr. Vol. 11-A, 40:22-41:2; Knodel Test., Tr. Vol. 1-A, 91:10-17; Def. Ex. C at Tab Net Emissions Change; *see also* Pl. Ex. 493, at AM-02231873, at "projected Emissions" tab (showing even higher projected SO_2 emissions of 17,018 for Unit 2 in 2012).

403. Ameren excluded every ton of the projected emissions increase on the basis that Unit 2 was capable of accommodating all of the increases in the baseline. Ameren provided no other reason for excluding the projected emissions increases in its Original Reasonable Possibility Analysis. Knodel Test., Tr. Vol. 1-A, 91:10-17. Mr. Hutcheson stated that there was no mechanism in his spreadsheet (Def. Ex. C and D) to account for whether the projected increase was related to the project. He testified that the relatedness question was a "qualitative" one not a "quantitative" one. Hutcheson Test., Tr. Vol. 11-A, 80:22-81:3.

404. Ameren did not rely on any guidance or applicability determinations in making their capable of accommodating determination. Whitworth Test., Tr. Vol. 11-A, 102:3-8, 103:24-104:3.

405. In late 2010, well after Ameren had completed the Unit 2 boiler upgrade, Mr. Hutcheson was asked by Ameren's in-house counsel, Susan Knowles, to revise his analysis. Hutcheson Test., Tr. Vol. 11-A, 85:3-11; Naslund Test., Tr. Vol. 6-B, 18:14-19; Hutcheson Dep., April 24, 2014, Tr. 115:2-12. Mr. Hutcheson used the EDF case to perform the Amended Reasonable Possibility Analysis. Hutcheson Dep., April 24, 2014, Tr. 117:10-20; Hausman Test., Tr. Vol. 4-B, 87:11-14.

406. Mr. Hutcheson completed the Amended Reasonable Possibility Analysis in early 2011, almost a year after the Unit 2 project had begun, and then only after EPA had issued a Notice of Violation to Ameren and after this lawsuit had been filed. Knodel Test., Tr. Vol. 1-A, 92:14-24, 93:15-19; Hutcheson Test., Tr. Vol. 11-A, 55:2-56:9, Def. Ex. D; RFA No. 7.

407. Mr. Hutcheson was asked to perform the Amended Reasonable Possibility analysis in order to incorporate a 2.4% efficiency improvement expected from the 2010 outage. No efficiency improvement had been incorporated into the Original Analysis. Mr. Hutcheson was not asked to make any other changes to the inputs into the analysis, such as changes that reflected the full extent of the capacity or availability improvements at Unit 2. Hutcheson Dep., April 24, 2014, Tr. 115:13-23; 117:10-20.

408. Ameren's expert, Mr. King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes. Mr. King agreed that in using such a run, a source runs the risk of looking like it is "cooking the forecast" to project no emissions increase. King Test., Tr. Vol. 6-B, 67:20-68:13.

409. Even with the changes made to the efficiency input, Ameren's Amended Reasonable Possibility Analysis still "projected" an increase of SO_2 emissions of 2,059.30 tons per year. Knodel Test., Tr. Vol. 1-A, 93:3-5; Def. Ex. D. As with its original analysis, Ameren excluded every ton of the projected emissions increase on the basis that the unit was capable of accommodating those emissions in the baseline period. Ameren provided no other basis for excluding those emissions increases. Knodel Test., Tr. Vol. 1-A, 93:6-14.

B. Ameren's Post Hoc Reasonable Possibility Analysis is Substantively Flawed

1. Ameren's calculations fail to model all of the performance improvements expected from the boiler upgrades

410. Ameren's Reasonable Possibility Analysis was based on its computer simulations performed for fuel budgeting purposes in January 2010. Those simulations include an 18 MW increase in Unit 2 capacity and a 2% improvement in unit availability—resulting in a 95% EAF—for the unit following the boiler work at issue in this case. *See* FOF 338, 353.

411. But project justification documents developed in 2009 projected significantly better performance at Unit 2 following the work. The CPOC report relied on a 22.5 MW increase in unit capacity as a result of the boiler work, as well as a 4.2% improvement in availability—resulting in a nearly 97% EAF—for the unit following the upgrades. *See* FOF 157, 158, 253.

2. Ameren's capable of accommodating approach

412. Ameren calculated the emissions the unit was capable of accommodating before the project by using the amount of time the unit was available to operate and multiplying that by the 95th percentile emissions rate (in pounds per hour). Hutcheson Test., Tr. Vol. 11-A, 41:3-17, 47:20-48:6, 68:16-24. Mr. Hutcheson calculated the 95th percentile emissions rate in Def. Ex. C, Tab Sheet1 and the results are shown in columns X and Y of the tab. Hutcheson Test., Vol. 11-A, 46:18-47:1.

413. Mr. Hutcheson's use of the 95 percentile emissions rate was not based on anything in the New Source Review rules. Hutcheson Test., Tr. Vol. 11-A, 69:13-70:5. Nor was it a standardized practice within Ameren. In fact, he used a 97th percentile emissions rate for nitrogen oxides for the same project. Hutcheson Test., Tr. Vol. 11-A, 78:3-22; Def. Ex. C at Tab RI U2 W2010 Detail.

414. In selecting the emissions rate for the capable of accommodating analysis, Mr. Hutcheson wanted to pick a rate that was "representative of what the unit could accommodate in

the baseline." The value he picked was in the top five percent of emissions rates that the unit achieved during the baseline period and that the median value would have been the 50th percentile. He also testified that he "would have no doubt" that there could be a big difference between the 95th percentile value and the 50th percentile value. Hutcheson Test., Tr. Vol. 11-A, 70:12-71:11.

415. Mr. Hutcheson did not look to see whether Unit 2 actually ran at the 95th percentile value for even 24 hours. Hutcheson Test., Tr. Vol. 11-A, 73:8-11.

416. The 95th percentile calculation that Mr. Hutcheson said was a representative emissions rate for Unit 2 actually included several hours in which Unit 2 was emitting at a rate well over what is allowed by its permit. Def. Ex. C at Tab Sheet1 (Column L, Rows 4563-4574 and 4590-4591); Hutcheson Test., Tr. Vol. 11-A, 73:12-21.

417. By using the 95th percentile emissions rate, Ameren calculated it would have accommodated about 17,550 tons of SO_2. Hutcheson Test., Tr. Vol. 11-A, 67:5-16. That much annual pollution would be more than Unit 2 had emitted since 1995, when the units were required to make reductions under the Acid Rain program. Declaration of Steven Whitworth (Pl. Ex. 926), at p. 10; Hutcheson Test., Tr. Vol. 11-A, 67:20-68:6; Knodel Test., Tr. Vol. 1-A, 56:1-4.

418. Mr. Hutcheson testified that had he used an average SO_2 emissions rate rather than the 95th percentile rate, it would "essentially be recalculating the baseline." Hutcheson Test., Vol. 11-A, 47:12-14. This is incorrect. Ameren's capable-of-accommodating calculation is based on the unit's *availability*, not on the actual operation. It calculates the additional emissions impact from running every hour the unit was available.

419. Had Mr. Hutcheson used the 50th percentile value for the SO_2 rate, even Ameren's flawed analysis would show the project triggered New Source Review. This can be seen from Def. Ex. C. Column Y on Sheet1, which has the results of the 95th percentile calculation. The calculation is linked to the ultimate emissions calculation set forth in Tab Net Emissions Change. Hutcheson Test., Vol. 11-A, 76:8-24; Def. Ex. C.

420. When clicking on the interactive formula bar for Cell Y8 in Tab Sheet1, the user can change .95 to .5 and thus run the calculation using the 50th percentile. After doing so, the Net Emissions Change tab automatically changes: the capable-of-accommodating number becomes 197 tons, the net change (the emissions increase) becomes 2,334 tons, and the spreadsheet indicates that the project triggers New Source Review. Def. Ex. C at Tab Net Emissions Change (Columns E, G, and I).

Using 50th percentile SO2 rate (3,491 lb/hour)

Unit	Pollutant	Baseline Emissions (tons/year)	Projected Actual Emissions (tons/year)	Capable of Accomodating Emissions (tons/year)	Excluded Emissions (tons/year)	Net Change (tons/year)	Significance Level (tons/year)	Significant (Yes/No)
	NO_x	2,099.73	2,522.83	459.51	423.10	-	40	No
Rush Island 2	SO_2	14,287.73	16,818.88	***196.88***	***196.88***	***2,334.27***	40	***Yes***
	PM_{10}	56.24	67.73	11.28	11.28	0.20	15	No

3. No analysis of relatedness

421. Mr. Hutcheson testified that to assess whether the increase was related to the project he talked to several people including his boss, Ken Anderson, and Steven Whitworth, the

head of the Environmental Services Department. None of the engineers who planned the outage were involved. Hutcheson Test., Tr. Vol. 11-A, 81:4-16.

422. Mr. Hutcheson testified that they discussed the heat rate, maximum design rate of the boiler, and SO_2 emissions rate. They concluded that those characteristics would not change due to the projects and thus any increase was not related to the projects. Hutcheson Test., Vol. 11-A, 49:17-50:21.

423. In performing the New Source Review analysis for Unit 2, Mr. Hutcheson did not look at whether availability was expected to increase as a result of the project. He testified that if the unit was capable of accommodating additional demand, "the availability is not necessarily relevant" and that it "wasn't necessary" to look at availability for his analysis. Hutcheson Test., Vol. 11-A, 82:16-25.

424. In contrast to Mr. Hutcheon's trial testimony, Ameren in fact uses availability predictions as part of its process to determine how much coal to buy. The company does so because the more available a unit like Rush Island is, the more it will generate and the more coal it will need. Naslund Test., Tr. Vol. 6-B, 11:6-16.

425. Ameren also used availability in the *baseline* as the basis for its capable of accommodating calculations. As Mr. Hutcheson explained, the company looked to availability to determine what the unit was capable of generating before the project. Hutcheson Test., Tr. Vol. 11-A, 44:9-14, 87:4-12.

426. In Rule 30(b)(6) testimony, Steven Whitworth, the head of Ameren's Environmental Services Department, testified as Ameren's corporate representative. Mr. Whitworth testified that he believed emissions that a unit was capable of accommodating are per se unrelated. In the Rule 30(b)(6) deposition, Whitworth testified that, "The emissions that the

unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Dep., Dec. 4, 2013, Tr. 38:4-12; Whitworth Test., Tr. Vol. 11-A, 101:19 – 102:2.

C. Nothing in Ms. Ringelstetter's Analyses Excuses Ameren's Failure to Perform Appropriate NSR Projections

1. Ms. Ringelstetter failed to address relatedness for either unit

427. Changes in availability would affect how much the unit was projected to generate. Ringelstetter Test., Tr. Vol. 11-B, 78:3–9.

428. Changes in unit capacity would affect how much the unit was projected to generate. Finnell Test., Tr. Vol. 10-A, 9:7–10.

429. Ms. Ringelstetter examined selected ProSym modeling files and observed that Ameren projected changes in the Rush Island units' availability and capacity following the boiler work at issue in this case, but testified that those changes had nothing to do with the boiler work. *See*, *e.g.*, Ringelstetter Test., Vol. 11-B, 56:10–15.

430. Ms. Ringelstetter noted that the maximum capacity at Rush Island Unit 2 was projected to be 11 MW above baseline levels following the boiler upgrades, but she attributes the capacity increase entirely to the LP turbine work performed in 2010. Ringelstetter, Vol. 11-B, 17:20–24 & Ameren's Summary Exhibit XF_2 (indicating 11 megawatt increase).

431. However, her baseline capacity number is not a measure of the unit's actual performance based on operating data; rather it is a reported number that tracks Ameren's Capability Tables. Ringelstetter Test., Tr. Vol. 11-B, 73:12–74:9.

432. Ameren's documents and witnesses stated that the company's 2005 Capability Tables were "unrealistically high" and were later adjusted downward significantly in February, 2006. Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling which show adjustments from the "unrealistically high" 610 MW to values between 581-596 MW). Since Ameren's selected baselines for both units include substantial amounts of 2005, Ms. Ringelstetter's 11 MW number significantly understates the projected capacity increase at Unit 2 compared to Ameren's documents and data. FOF 157, 289, 299, 300, 301.

433. Ms. Ringelstetter further testified that Ameren's ProSym models projected an increase in availability at each unit following the boiler upgrades, but stated that the increase is not substantial enough to appear to be a meaningful difference, and so discounts it entirely for her emissions assessment. Ringelstetter Test., TR. Vol. 11-B, 17:4–12.

434. Ms. Ringelstetter discounted these increases even though the availability forecast for Ameren's economic justification of the work at Unit 2 was fine-tuned to the tenth of a percent, and even that tiny variation meant hundreds of thousands of dollars dropped out of the analysis. June 15, 2009 Email (Pl. Ex. 895), Meiners Test., Tr. Vol. 7-B, 34:9-35:25.

435. Ms. Ringelstetter offered no opinion on how—if at all—the projects at issue in this case would have been expected to change the operations of the Rush Island units. Ringelstetter Test., Tr. Vol. 11-B, 59:23–60:3.

436. Nor did Ms. Ringelstetter offer any independent opinion on whether or to what extent the low pressure turbine replacement that occurred at Rush Island Unit 2 alongside the boiler modifications had any impact on unit operations or performance. Ringelstetter Test., Tr. Vol. 11-B, 60:4–9.

437. As such, all of her emissions analyses—and all of the emissions she concludes should be excluded from the emissions projection—rest on the assumption that *none* of the projected emissions increases were caused or enabled by the projects at issue in this case. Ringelstetter, Tr. Vol. 11-B, 18:9–11 & 22:2–9.

438. When she developed her calculations for her expert report, Ms. Ringelstetter believed it was *irrelevant* whether the projects at issue in this case resulted in performance improvements. Rather, by her calculations, the only thing that mattered for the demand growth exclusion was whether the unit "could have accommodated" the projected emissions levels during the baseline. Ringelstetter Test., Tr. Vol. 11-B, 77:2–17.

2. Ms. Ringelstetter's Unit 1 analysis relies on faulty assumptions

a. Background regarding ancillary services

439. Ancillary services are things other than simple electric generation that utilities provide to keep the electric grid operating reliably. Generally they involve promises that certain amounts of generation will be held in reserve or would be dedicated to real-time adjustments in response to market fluctuations. When a unit was providing some ancillary services, it would typically not be operating at its full capabilities. Hamal Test., Tr. Vol. 9-A, 23:4–6; Haro Test., Tr. Vol. 9-A, 99:21–100:13.

440. On January 1, 2007, Ameren Missouri entered into a short term contract to provide ancillary services to its Illinois affiliates. Def. Ex. HX. That contract was to last "from January 1, 2007 until the earlier of (i) December 31, 2007, or (ii) the date during calendar year 2007 on which the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") ancillary services market for Ancillary Services is operational." Def. Ex. HX at 1.

441. The short-term contract was later renewed when the launch of MISO's ancillary service market was further delayed. Haro Test., Tr. Vol. 9-A, 133:24–134:7.

442. The contract did not specify how much of the ancillary services described in the contract would be provided by Rush Island units or how often the units would be assigned to provide those services. Def. Ex. HX at Article 3, § 3.1.1 and Schedule A.

443. As of January 2009, ancillary services such as regulation hours and spinning reserves were offered into—and cleared through—MISO's ancillary services market. Hamal Test., Tr. Vol. 9-A, 43:10–12; Ringelstetter Test., Tr. Vol. 11-B, 95:10–14.

444. As Mr. Hamal explained: "In order to provide [ancillary services], you can't be at full load. You have to back off. You have to be at partial load. And so when prices are really high, I'd rather have a high-cost unit at partial load than a low-cost unit." Hamal Test., Vol. 9-A, 24:11–15.

445. The Rush Island units would not be expected to provide ancillary services once MISO's ancillary service market was implemented. Ameren's contract for ancillary services was never intended to extend beyond when MISO's ancillary services market started up in 2009. Haro Test., Vol. 9-A, 102:1-14, 134:4-7.

446. The MISO ancillary services market helped optimize the provision of ancillary services like regulation and spinning reserves: "it allow[ed] MISO to look at the fact that not only is that unit providing regulations, but it's not providing energy. So if that's a low-cost unit providing regulation, there may be a high-cost unit that could provide that regulation and save the system money overall." Hamal Test., Tr. Vol. 9-A, 24:5–10.

447. Since the Rush Island units are relatively-low cost units that run all the time, (Hamal, Tr. Vol. 9-A, 26:16–17), the implementation of the MISO ancillary services market

meant they would be "held back" little if any to provide ancillary services once those services were cleared through the market system. Hamal Test., Tr. Vol. 9-A, 24:20–24.

448. Ameren's chief modeler, Mr. Timothy Finnell, explained that in order to model ancillary services like regulation hours or spinning reserves in ProSym, Ameren would inflate a unit's partial outage rate, thereby depressing the unit's availability in the model. That would, in effect, lower the output of the units that were assigned to regulation in the model. Finnell Test., Tr. Vol. 9-B, 99:3–7; *see also* Ringelstetter Test., Tr. Vol. 11-B, 62:4–63:17.

449. Mr. Finnell admitted that assigning units regulation hours or ancillary services in the model would affect how much generation they were expected to produce and how much coal they were expected to burn in the forecast years. Ameren modeled ancillary services by increasing a unit's partial forced outage rate. Increasing the forced outage rate results in reduced generation and coal burned in the model. Finnell Test., Tr. Vol. 9-B, 99:3–100:19.

450. In 2008, Mr. Finnell, then head of Operations Analysis in Ameren's Corporate Planning Department and in charge of the company's ProSym modeling, testified before the Missouri Public Service Commission about how the sale of ancillary services impacted the company's business forecasts:

> Q. Is AmerenUE selling ancillary services to the utility operating subsidiaries owned by Ameren Corporation in Illinois?
>
> A. Yes, for 2008, AmerenUE is selling 39 MW of spinning reserves and 68 MW of supplemental reserves to Illinois affiliates.
>
> Q. Does the PROSYM model include the sales of ancillary services to these Illinois utilities?
>
> A. No. The sales of these ancillary services were not included because they are based on a short -term contract that will end when the MISO ancillary service market begins.

Finnell MPSC Test. (Pl. Ex. 439), at 12:16–23.

451. Neither of Ameren's two experts hired to discuss dispatch and market issues quantified how the provision of ancillary services influenced Rush Island operations before the projects were performed or once the modifications were completed. Mr. Hamal "didn't get into the details and quantify how much regulation Rush Island did," focusing instead on the general market structure. Hamal Test., Tr. Vol. 9-A, 44:3-5. Ms. Ringelstetter, despite offering an opinion that Ameren's modeling of ancillary services was "entirely appropriate," (Ringelstetter Test., Tr. Vol. 11-B, 66:4–6), did not mention ancillary services, regulation hours, or spinning reserves in her expert report, nor was she aware of any "specifics" regarding Ameren's short-term ancillary service agreements. Ringelstetter Test., Tr. Vol. 11-B, 66:10–67:10.

b. Ms. Ringelstetter's modeling choice

452. For the analysis in which she concludes that projected emissions would not increase following the Unit 1 modification work, Ms. Ringelstetter uses a ProSym modeling effort that includes two artificial adjustments.

453. First, the ProSym modeling run that Ms. Ringelstetter used when assessing the 2007 project at Rush Island 1 included an input for that unit which was intended to reflect its provision of ancillary services. Despite the short-term nature of the services as described above, she used a run where Unit 1 was modeled as holding back 15 MW for regulation hours for *every year* of the model forecast, 2007 through 2012. Ringelstetter Test., Tr. Vol. 11-B, 63:18–64:2; *see* Hausman Test., Tr. Vol 4-B, 97:3-9.

454. Second, Ms. Ringelstetter claims the modeling effort suffered from what she calls a bias in the inputs which requires a downward adjustment to the model's projections. However,

Ameren never performed such an adjustment when it did its own analyses, and in fact other modeling efforts did not suffer from this bias. Hausman Test., Tr. Vol. 4-B, 98:9–99:12.

455. Without either of these adjustments, Ms. Ringelstetter's analysis would show a significant projected increase in Rush Island 1 operations and pollution above baseline levels. Hausman Test., Tr. Vol. 4-B, 99:13–23.

VI. THE 2007 AND 2010 BOILER UPGRADES TRIGGERED TITLE V REQUIREMENTS

456. The Clean Air Act Title V permit for the Rush Island Plant contains a condition restating the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2. Declaration of Steven Whitworth (Pl. Ex. 926), at attached Title V Permit, AM-02511339-2511393, at 2511362.

457. Ameren has not obtained a permit for its major modifications, and the Rush Island Title V permit does not incorporate PSD requirements for its major modifications. Pl. Ex. 926, at attached Title V Permit, AM-02511339-2511393, at 2511348-350 (Listing no Unit Specific Emission Limitations for SO_2).

CONCLUSIONS OF LAW

I. OVERVIEW

Under the Clean Air Act's PSD program, an existing source of pollution must obtain a permit and install state-of-the-art emissions controls when the source makes a "major modification." *Ameren SJ Decision*, 2016 WL 728234, at *4. The United States claims Ameren violated the PSD program's requirements by making major modifications to Units 1 and 2 at Rush Island without obtaining applicable permits or installing required emissions controls. The only disputed element of proof is whether the projects performed on Units 1 and 2 were "major modifications" under the law. *See* Subsection II.A (other elements of proof undisputed). To prove a major modification, the United States must show the work at issue was (1) "a physical change or change in method of operation that (2) would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *2 (citing 40 C.F.R. §52.21(b)(2)).

For the purposes of the first prong of the test, the term "physical change" is extremely broad, and there is no dispute that the projects were physical changes. *Id.* at *4. But not all physical changes trigger PSD permitting requirements. Routine maintenance, repair, and replacement projects are excluded from the definition of "major modification." *Id.* Ameren argues the challenged Rush Island projects were routine maintenance projects and as a result exempt from being considered "physical changes." Subsection III.A below explains why the challenged projects are not routine maintenance.

For the purposes of analyzing the second prong of the test, Subsection II.B below explains that the projects would be expected to result in—and did result in—a significant net emissions increase. Because the projects were physical changes that would result and did result in a significant net emissions increase, they were major modifications under PSD.

Because the United States has proved the Rush Island projects were major modifications, Ameren violated the PSD provisions of the Clean Air Act because it did not obtain the required permits or meet other PSD requirements before beginning construction. In addition, as explained in Subsection II.C below, Ameren also violated the Title V provisions of the Clean Air Act.

II. THE UNITED STATES PROVED THAT AMEREN VIOLATED THE PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V PROVISIONS OF THE CLEAN AIR ACT

A. Undisputed Elements of Proof

The only disputed element of proof is whether the projects were major modifications under the law.

There is no dispute that:

- Ameren is a "person" under the applicable law and the owner and operator of the Rush Island facility. 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2); FOF 2.
- Rush Island Units 1 and 2 are each a "major emitting facility," a "major stationary source," and an "electric steam generating unit" under the applicable PSD and Title V provisions. 42 U.S.C. § 7479(1), 40 C.F.R. § 52.21(b)(1) and (b)(31); FOF 13.
- EPA provided sufficient pre-filing notice of the violations to Ameren and the State of Missouri and provided notice of the filing of this case to the State. 42 U.S.C. § 7413(a), (b); FOF 18-21.
- At the time of the projects, Rush Island was in an area designated as attainment for SO_2. 42 U.S.C. § 7471; FOF 11. Therefore the PSD program applies.

B. The Projects Should Have Been Expected to Cause—and Did Cause—Emissions Increases

1. Legal standard

There are two ways to establish PSD liability. The United States can satisfy its burden by proving either that: (1) the source should have expected an emissions increase related to the project (the expectations approach); or (2) an emissions increase related to the project actually occurred (the actual emissions approach). *Ameren SJ Decision*, 2016 WL 728234, at *16; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

Regulations establish how to compare pre- and post-project emissions. The pre-project "baseline" is any 24 consecutive months in the 5 years before the project. 40 C.F.R. §52.21(b)(48)(i). The post-project period is the maximum annual emissions in any one of the five years after the project. 40 C.F.R. §52.21(b)(41)(i). The difference between the baseline and post-project high emissions year is the emissions increase for PSD purposes. An increase of 40 tons or more of SO_2 per year is "significant" under the regulations. 40 C.F.R. §52.21(b)(23)(i). In this case, there is no evidence of any creditable emissions decreases, so any emissions increase proven is the same as the net emissions increase. *See* 40 C.F.R. § 52.21(b)(3).

Under the expectations approach, courts must determine what a source should have expected at the time of the project. To prevail, the United States "must show that at the time of the projects [defendant] expected, or should have expected, that its modifications would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *13 (citing cases and quoting *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013) (internal quotations omitted)).

Ameren's internal documents are relevant to what the company expected or should have expected. *See*, *e.g.*, *Ala. Power*, 730 F.3d. at 1286-87; *United States v. La. Generating LLC*, 929 F. Supp. 2d 591, 593-594 (M.D. La. 2012) ("The documents clearly show outages were a problem and the company planned to work on the reheaters in order to fix those problems."); *Ohio Edison*, 276 F. Supp. 2d at 834 ("The documents prepared to justify the expenditures described the various purposes of the projects to include replacement of major components to increase the life and the reliability of the units.").

Under the actual emissions approach, the question is simply whether SO_2 emissions actually increased by more than 40 tons per year as a result of the project.

Under either approach, additional operations made possible by a project must be attributed to that project. As EPA has explained, "where the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996). A series of court decisions have echoed this requirement.

"If an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5; *see also Duke Energy 2007*, 549 U.S. at 577-78 (noting regulatory provision that requires assessing number of hours the unit is or probably will be running); *Ala. Power*, 730 F.3d at 1281; *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir. 2006) (revitalizing a plant to operate more hours may trigger PSD obligations); *Ohio Edison*, 276 F. Supp. 2d at 834-35 (finding PSD liability for projects that were "intended to result in increased hours of operation as a result of a reduction in . . . forced outages").

Even when there is evidence that emissions will or did increase after a project, a source may demonstrate that the increased emissions should be excluded from PSD review under the "demand growth exclusion." Under the demand growth exclusion, a source must exclude from its calculations:

> any emissions increases that "an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 67 Fed.Reg. at 80,277 (codified at 40 C.F.R. § 52.21(b)(41)(ii)(c)).

New York v. U.S. E.P.A., 413 F.3d 3, 31 (D.C. Cir. 2005) ("*New York I*"). After substantial argument about the application of the demand growth exclusion at summary judgment, I explained its application as follows:

> if emissions increase because a project enables the unit to meet previously unmet demand during peak hours, for example, those emissions increases are likely related to the project and therefore do not qualify for the demand growth exemption. . . if the un it undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification.

Ameren SJ Decision, 2016 WL 728234, at *10.

Finally, Congress intended for the PSD rules to "have broad application." *Id.* (citing *Ala. Power Co. v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 1979)).

2. **The evidence shows that Ameren should have expected an emissions increase related to each project, and such an emissions increase occurred**

The core facts of this case show that before Ameren performed the challenged projects, problems with the components at issue were limiting the units' performance. Replacing those components would improve performance and result in additional use and pollution. That was what Ameren should have expected before the work began. The evidence shows that is what Ameren *did* expect. The evidence also shows that is exactly what happened.

Two key—and undisputed—characteristics of the Rush Island units underlie the entire discussion of emissions increases. First, the Rush Island units are big sources of pollution. That means even small performance improvements can enable a 40-ton increase in SO_2. For example, there is no dispute that it only takes an additional 21 hours of operations at full power for a Rush Island unit to emit more than 40 tons of SO_2. FOF 190.

Second, the Rush Island units are "baseload" units. FOF 6. They are relatively cheap sources of electricity. FOF 50. The market for electricity, which puts a premium on price, drives these baseload units to operate as much as they can. *Id.* That means the Rush Island units run every hour they are available—and at high or even maximum levels during hours of "peak" demand. FOF 6, 371-372. Moreover, Rush Island's baseload status means that if the units improve their performance in any way that allows them to generate more electricity, the market will call on the units to generate more electricity. FOF 50, 215. As Ameren's retired executive Charles Naslund explained at trial, Ameren plans its coal purchases based in part on availability projections because the company knows that the more available the Rush Island units are, the more they will run. FOF 424. That additional generation requires additional coal—and means additional pollution. FOF 205.

These two facts lead to a logical conclusion: if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels. Ameren's witnesses and documents recognize this simple relationship. FOF 424, 427-428, 448. And using Ameren's computer modeling software, United States' expert Ezra Hausman illustrated that a mere one-megawatt improvement in unit capacity would lead to an additional 23 tons per year of SO_2 pollution and that a one percent improvement in unit availability would result in about 150 extra tons of SO_2 per year. FOF 336-337, 339-41. Ameren should have expected the Rush Island boiler upgrades to result in at least an additional 40 tons of SO_2 pollution—and that is exactly what happened.

a. The Koppe-Sahu emissions calculations show a predicted increase at Unit 1 and were confirmed by an actual increase

Before the projects, the components at issue were causing outages and deratings at Unit 1. FOF 47-88. Ameren's availability data showed that the economizer, reheater, lower slope tubes, and air preheater were the predominant cause of availability losses at the unit, so Ameren decided to replace them with redesigned components. FOF 136, 138-139, 222-223. The decision to replace these components was the result of a lengthy and deliberate process and was ultimately approved by a series of managers and executives, culminating with the Ameren parent company CEO. FOF 136, 177. One of the bases of that approval was the expectation that the replaced components would cause *no* outage time for *20 years* following the projects. FOF 38, 145-149. Looking at the unit as a whole, Ameren expected that Unit 1's long-term availability would increase to 95% after the work was done, about a 3% increase compared to the PSD baseline. FOF 228.

The United States' expert Robert Koppe did his own analysis of how the project would affect Unit 1's performance. Mr. Koppe is a power plant engineer who has spent much of his career analyzing the performance of generating units on behalf of utilities and public service commissions using methodologies that courts have consistently found to be reliable. FOF 90-91; *see, e.g., United States v. Cinergy Corp.*, 623 F.3d 455, 459 (7th Cir. 2010); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 877 (S.D. Ohio 2003). Mr. Koppe analyzed the problems affecting Rush Island during the baseline period and determined what Ameren should have expected to result from the work it did in the 2007 and 2010 outages. FOF 195.

Mr. Koppe started by identifying all the outage hours and deratings attributed to the components at issue during the baseline. He found that the equivalent availability losses due to the four components at issue totaled 336 hours in the baseline period, about half the unit's total outage time.[4] FOF 197, 222. Importantly, Mr. Koppe also looked at the condition of the unit as a whole and the other work performed during the 2007 outage. FOF 197-198. As Mr. Naslund explained at trial, Ameren was working hard to address any potential future problems during the outage. FOF 199. Mr. Koppe concluded that the other work performed during the 2007 outage would prevent availability from declining due to other potential issues. FOF 255. He also

[4] Ameren claims that Mr. Koppe and Dr. Sahu should have accounted for derates differently. This portion of Ameren's criticism has to do with what is known in the industry as a "utilization factor" and whether Mr. Koppe and Dr. Sahu should have used a different utilization factor for deratings than they did for outages, as Ameren's expert Marc Chupka testified he would have done. But Mr. Chupka is an economist, not a power plant engineer, and Dr. Sahu's use of a single utilization factor for both outages and deratings is exactly what the Electric Power Research Institute ("EPRI") has recommended since the 1980s. FOF 210. In fact, except for the purposes of this litigation, Ameren instructs its engineers to do the very same thing. FOF 210.

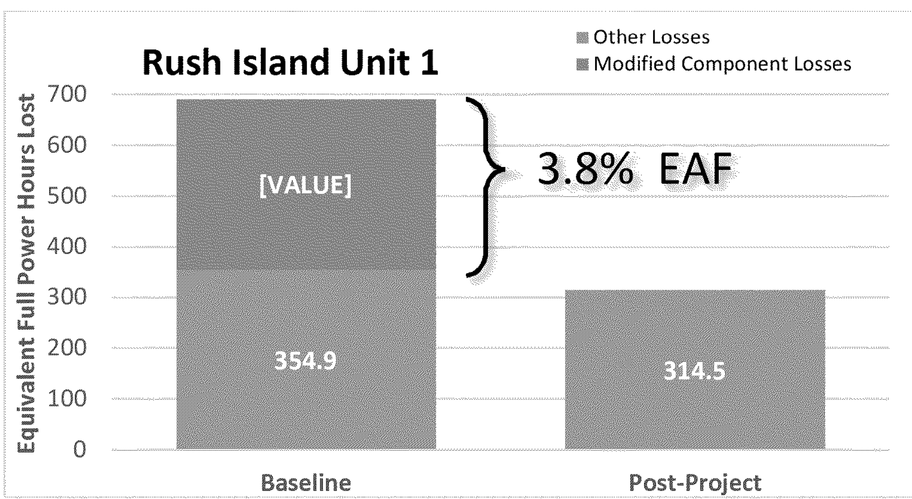
concluded that the project would completely eliminate availability losses from the components at issue and result in an availability improvement of 3.8% from the baseline, bringing Unit 1's availability to about 96% post-project.[5] FOF 224-225, 227. Mr. Koppe concluded—and Ameren witnesses and documents confirm—that availability would not have increased at all if these problematic components had not been replaced. Rather, it would have gotten worse. FOF 227, 231, 239, 255.

Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements, using a methodology that has been recognized as industry-standard by several courts. *See, e.g.*, *Ala. Power*, 730 F.3d at 1284-85; *La. Generating*, 929 F. Supp. 2d at 596. Dr. Sahu concluded, as Ameren did, that the company would utilize the regained hours at the same proportion as it had in the past. FOF 206, 208. Based on his and Mr. Koppe's analyses, Dr. Sahu calculated an expected increase in emissions of 608 tons of SO_2 post-project for Unit 1. FOF 232. Because Dr. Sahu's calculation was based on

[5] Ameren argues in its post-trial brief that Mr. Koppe testified that it would not be reasonable to expect the units could achieve over 95% availability post-project because "things happen" and "other components can fail." Ameren then argues that an increase to 95% at Unit 1 is no significant increase at all because Unit 1 had a baseline availability of 94.7%. There are two major flaws with this argument. First, Mr. Koppe did not testify that the units would not be expected to achieve over 95% availability; in fact, he testified that Ameren should have expected "the fairly long-term average equivalent availability" to reach about 95%, but "the best performance post-project" (which is the relevant measure) "would be more like 97 or 98 percent." Koppe Test., Tr. Vol. 3-A, 79:7-14. Second, Ameren's argument that there was no expected significant availability increase only works if its suggested baseline availability figure of 94.7% is accepted. That figure is at odds with Mr. Koppe's well-supported calculation that Unit 1's baseline availability was actually 92.1%. Ameren's calculations appear to be based on the exclusion of certain GADS events from its performance data, but Ameren offered no testimony at trial to support that approach.

the additional operation allowed by the project, the entire predicted increase is related to the work. *Id.*

Post-project results confirm Mr. Koppe and Dr. Sahu's calculations. In 2008, Unit 1 set its record availability with the best availability in the entire Ameren system. FOF 234; *see also* FOF 236. As Mr. Koppe and Ameren both expected, all the outages and deratings due to the replaced components were eliminated. FOF 237. Availability during the highest post-project emissions year reached 96.4%, which is 4.3% higher than the baseline. FOF 238. The entire expected improvement related to the project (3.8%) was realized. That improvement was an order of magnitude more than the 0.3% increase needed to result in 40 additional tons of SO_2. FOF 191. The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work was completed, Unit 1's actual availability climbed to 96.4% and it did not experience any losses due to the new components and actual availability. FOF 237–38.



EAF:	92.1%	96.4% (+ 4.3%)

With the availability improvement came an actual increase in emissions of 665 tons of SO_2. FOF 664. Those additional tons were made possible by the availability improvement and are related to the project. FOF 239.

At trial, Ameren sought to exclude any testimony from Mr. Koppe and Dr. Sahu on the cause of the actual increase. As discussed below (*see* Subsection I.A on Evidentiary Issues), I am denying Ameren's motions to strike this testimony because I find that the challenged opinions were properly disclosed. But even without the challenged testimony, the evidence shows an actual and significant net increase of emissions related to the project for both units. Ameren has *not* challenged the admissibility of the testimony by Mr. Koppe and Dr. Sahu that:

- An availability improvement of just 0.3% or an additional 21 hours of operation would cause a more than 40 ton-increase in pollution.
- The work would eliminate all availability losses due to the components, increase overall availability by far more than 0.3%, and increase pollution.[6]
- Post-project data shows those predictions came true: there were no component losses of any kind in the post-project year, availability improved by much more than 0.3%, the unit operated hundreds of hours more, and pollution increased.

FOF 267. Mr. Koppe and Dr. Sahu made a prediction based on improved unit performance, and the actual data confirmed those predictions. As Mr. Koppe explained at trial:

> [If] half of all the outage time that's occurring is eliminated by the projects and the effect of all th e other equipment in the unit stays the same . . . then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.
>
> ***
>
> The causation of what actually happened is obvious from the—from the data.

Koppe Test., Tr. Vol. 4-A, 115:18-25, 4-B, 18:1-4.

[6] Ameren concedes that Unit 1 availability was projected to increase by 1.3%. Ameren Br. at 5 (Doc. 835).

Here, based on the substantial and credible evidence presented showing how the project would cause improvements in availability and, as a result, increase emissions, I am able to find, even without explicit expert testimony, that the predicted cause of the increase was the cause of the actual emissions increases. *See, e.g.*, *United States v. Crenshaw*, 359 F.3d 977, 988 (8th Cir. 2004) (citing *Jackson v. Virginia*, 443 U.S. 307, 319 (1979) (noting court authority "to draw reasonable inferences from basic facts to ultimate facts").

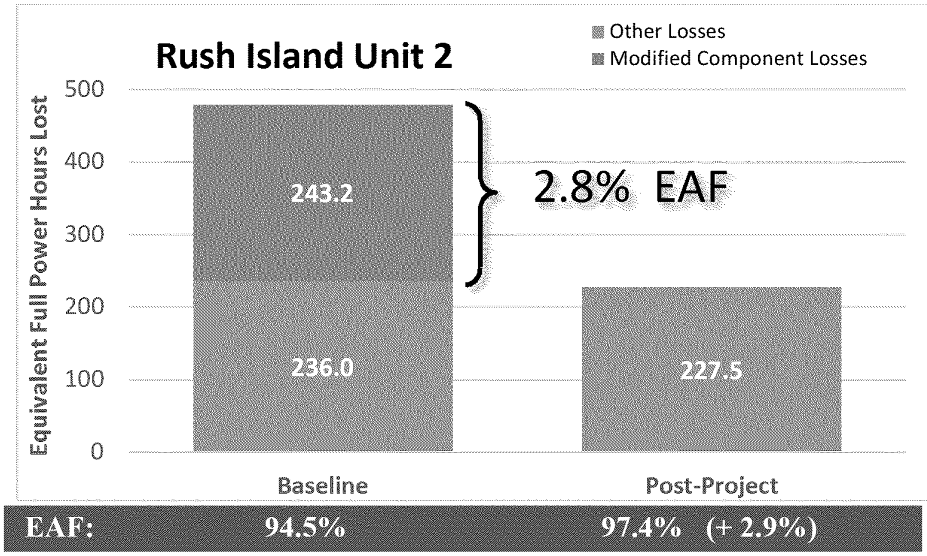
b. The Koppe-Sahu emissions calculations show a predicted increase at Unit 2 and were confirmed by an actual increase

The background story of Unit 2 is the same as Unit 1. Unit 2 had the same problems with the components at issue limiting the unit's availability in the time leading up to the outage. As with Unit 1, Mr. Koppe analyzed the expected impact of the 2010 project on Unit 2's availability. FOF 47–88, 145–47, 197–98. Mr. Koppe found that the outages and deratings at Unit 2 caused by the economizer, reheater, and air preheater resulted in about 245 equivalent lost hours during the baseline, slightly more than half the total lost operating time. FOF 247. As with Unit 1, Mr. Koppe examined the overall condition of Unit 2 and found that other work performed during the outage would prevent availability from getting worse and that the component replacements would result in an availability improvement. FOF 251. For Unit 2, he predicted that the project would completely eliminate all of the losses due to the three components at issue and, by itself, would improve Unit 2's availability by 2.8%. FOF 248, 251. None of these improvements would be possible if Ameren had not replaced the reheater, economizer, and air preheater. Rather, without the project, availability at Unit 2 would have decreased, not increased. FOF 255.

Ameren argued at trial that availability could *never* increase beyond 95%. But former plant manager Robert Meiners agreed with Mr. Koppe and Dr. Hausman that the long-term availability forecast of 95% meant individual years would be as high as 97% or 98%. FOF 257. As noted above, the relevant PSD inquiry compares the baseline emissions to the year with the highest amount of projected emissions in the five-year post-project period. Tellingly, Ameren already knew that Unit 1 set an availability record after the 2007 project of nearly 97% in 2008. FOF 254. When seeking re-approval of the Unit 2 project in 2009, Ameren's engineers explicitly stated they expected Unit 2 to perform "at least equal to, if not better than," Unit 1 and expected a 3–4% availability improvement. FOF 256. Mr. Meiners confirmed this at trial, testifying that the availability input used in financially justifying the Unit 2 outage to senior company executives was almost 97%. FOF 253.

The post-project data shows that Unit 2's availability actually reached 97.4% in the highest year after the project. FOF 260. As Ameren's trial witness Scott Anderson testified after reviewing Unit 2's historic availability statistics, the difference between the pre- and post-project performance was "night and day." FOF 261. Comparing the baseline to the post-project year, Mr. Koppe predicted an availability improvement of 2.8% due to the project alone, and Ameren actually got an improvement of 2.9%. FOF 259. The components at issue caused no availability losses after the project, as Mr. Koppe predicted. *Id.* As with Unit 1, the availability improvements far exceeded the small changes that would cause Unit 2 to emit 40 additional tons of SO_2.

The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work, there were no losses due to the new components and actual availability climbed to 97.4%. FOF 259–60.



Based on Mr. Koppe's prediction of regained availability, and using the method described above, Dr. Sahu calculated an expected increase of 415 tons per year of SO_2 in Unit 2 that would result from the availability improvement alone. FOF 258.

Separate from the expected increase in emissions based on availability improvements, Ameren also should have expected an emissions increase at Unit 2 based on capacity improvements. After the Unit 1 outage, Ameren saw a significant *capacity* gain as a result of the project. FOF 269. Ameren and Mr. Koppe both analyzed how a similar capacity gain would affect Unit 2's post-project operation.[7] [8]

There is no dispute that Ameren realized a gain in capacity, measured in megawatts ("MW"), at Unit 1. FOF 269–70, 274. Ameren expected similar improvement at Unit 2. *Id.* In

[7] In addition, Ameren replaced the low pressure turbine during the 2010 outage, which would also be expected to affect performance.

[8] Ameren argues that Mr. Koppe and Dr. Sahu's analyses double count the effect of deratings already accounted for in its availability analysis in its capacity analysis, but Dr. Sahu clearly presented separate emissions calculations for the availability and capacity increases. FOF 258, 302-303. *See also* US Br. at 26 n.16 (Doc. 838).

a series of company documents from Fall 2007 until the time of the overhaul, Ameren engineers repeatedly stated that significant capacity increases (of up to 30 MW) would result from the boiler work. FOF 269–78. That expectation was included in the documents presented to corporate executives seeking approval of the Unit 2 project. That expectation was even used to calculate how the project would impact Ameren's shareholders and ratepayers. FOF 158, 276. For instance, in the justification for the outage work that was presented to Ameren's executives, the company's engineers explained exactly what benefits they assessed in determining the projected value of the project. The first benefit listed is "30 MW gain in summer (3 mos), 20 MW gain balance of year *from reheater, economizer and APH [air preheater] investment*." Pl. Ex. 110 at AM-02465690 (emphasis added); FOF 277.

As he did for availability, Mr. Koppe independently studied the data and information produced by Ameren and reached a conclusion similar to what Ameren's engineers found before the Unit 2 outage. Mr. Koppe confirmed that pluggage had limited Unit 2's capability during the pre-project period and that Ameren should have expected at least 22 MW of increased capability due to the boiler work. FOF 279. Another 12-15 MW of capability would result from the new LP turbine. FOF 280. Dr. Sahu calculated that an 18 MW capacity increase due to the boiler project alone would increase emissions by 417 tons of SO_2. FOF 303.

The post-project data confirmed the results of Mr. Koppe's analysis. In fact, Ameren reported its improved capacity to MISO, the North American Electric Reliability Council, and the Missouri Public Service Commission, among other outside entities, each time attributing a major portion of the unit's capacity increase to the boiler work at issue. For example, Ameren responded to an inquiry from the Missouri Public Service Commission in a rate case related to the Unit 2 2010 outage. In defending its requested rate increase, Ameren stated that unit capability improved by 34 MW, of which 22 MW were restored capacity. FOF 288–89. Similarly, Ameren reported that Unit 2's *summertime* peak capability had increased to nearly 650 MW gross "due to work completed during the 2010 major outage (replacement of lower pressure turbines and *numerous boiler modifications*)." FOF 287 (emphasis added).

Ameren's post-project reports are quite similar to what Mr. Koppe found in reviewing the post-project data. Mr. Koppe first analyzed Ameren's "Plant Information" database and determined that Unit 2's capability had increased by 38 MW, from 615 MW during the pre-project period[9] to 653 MW afterwards. FOF 296–99. An almost identical increase is observed by comparing Ameren's "full load" test reports. The average capability reported by Ameren in those reports increased by 37 MW, when comparing baseline (620 MW) and post-project (657 MW) periods. FOF 295, 301.

Of the overall increase in capability, Mr. Koppe determined that about 23 MW of the increase were due solely to the component replacements and would require more coal to be burned. FOF 300. Ameren's documents show that it had reached the same conclusion. The predicted and actual capability increases Mr. Koppe reports are right in line with what Ameren used in its financial justification for Unit 2 (22.5 MW) and far more than the 1.7 MW that would result in 40 additional tons of SO_2.

Based on the performance improvements predicted by Mr. Koppe, Dr. Sahu calculated increases of more than 400 tons of SO_2 due to either the availability increase or the capacity increase alone. FOF 258, 303. Both the availability and capacity improvements Mr. Koppe predicted were borne out by actual data. FOF 237–38, 259–60. After the 2010 project, overall

[9] Because Ameren did not produce complete Plant Information data from before 2006, Mr. Koppe used January 2006 -December 2007 for the pre -project period, since that was closest in time to Ameren's baseline.

emissions of SO_2 from Unit 2 increased by 2,171 tons per year. FOF 266. As a result, the actual emissions increase includes increases resulting from the availability increase and the capacity increase. Each is an order of magnitude larger than the PSD significance threshold.[10]

3. Dr. Hausman used Ameren's modeling to quantify the emissions impact from the projects

The conclusions of Mr. Koppe and Dr. Sahu are further supported by Dr. Hausman's analysis of Ameren's computer modeling efforts. Dr. Hausman is a modeler and market consultant with nearly 20 years of experience focused on the electric industry.

Ameren uses a sophisticated computer modeling program called ProSym to predict the operations of its generating fleet—including the Rush Island units—so it can plan accordingly. FOF 314–15. Ameren uses ProSym modeling for a number of things, including rate recovery proceedings before the Missouri Public Service Commission, fuel purchasing and planning, and informing capital investment decisions. FOF 315. Ameren has testified to the public service commission that its use of ProSym is "very well calibrated" and gives reliable projections of future unit performance. Plaintiff's Exhibit 439.

In the lead-up to the Rush Island overhaul projects—and in the normal course of its business—Ameren used ProSym to model and predict the Rush Island units' fuel needs ("heat input" in the industry parlance) for the years after the 2007 and 2010 major boiler outages. FOF 318–19, 329. Dr. Hausman performed two types of analysis based on Ameren's modeling. First, Dr. Hausman examined how varying specific inputs, such as the units' availability parameters or

[10] As noted in the discussion of Unit 1, even if I were to exclude testimony on actual emissions causation from Mr. Koppe and Dr. Sahu, which I will not, I can connect the dots myself to find the predicted—and realized—improvements caused the predicted—and realized—emissions increase.

maximum capacity values, would affect the model's projections for that unit's future performance. FOF 330–31. In effect, he investigated whether, and to what extent, the Rush Island units would actually use extra operating hours or extra capacity if the units were improved. The model that Ameren used routinely to simulate its units' operations showed that if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would take advantage of those performance enhancements, burning more coal and, as a result, emitting more pollution. FOF 332. In fact, the models showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption. *Id.*

The results of the ProSym runs confirm the admissions by Ameren's witnesses: performance improvements like capacity increases or availability gains would lead to additional operations and additional pollution. FOF 427–28. Dr. Hausman's sensitivity analyses quantify those relationships.

The following chart provides the results of Dr. Hausman's sensitivity analyses. Dr. Hausman ran several iterations of Ameren's ProSym model to identify what changes in forced outage rates, partial outage rates, and capacity would mean for coal consumption and pollution. FOF 334–41.

	Performance Measure	Δ Coal Consumption (Billion BTU)	Δ SO_2 Pollution (tons per year)
Rush 1	Forced Outage Rate (per 1%)	481	162
	Partial Outage Rate (per 1%)	408	138
Rush 2	Maximum Capacity (per 1 MW)	69	23
	Forced Outage Rate (per 1%)	566	189
	Partial Outage Rate (per 1%)	466	156

The demonstrated relationship between availability and capacity and emissions mean that a mere 0.3% improvement in availability[11] or a 1.7 MW increase in capacity is enough to cause the Rush Island units—modeled by Ameren in its regular business—to emit 40 additional tons of SO_2 pollution. FOF 333.

Dr. Hausman's second set of analyses compared the results of Ameren's modeling efforts, which included assumptions about improved unit availability and capacity beginning the year after the projects were performed, to model runs in which the Rush Island Units were not improved—that is, a scenario in which the outages that included the projects at issue in this case were never undertaken. FOF 342. These "with and without" analyses served to isolate the amount of the projected increase in unit operations and air pollution that was caused or enabled by Ameren's 2007 and 2010 outage work. FOF 343, 345. In other words, even though other factors contributed to unit operations and pollution, the comparison reveals how much of those emissions would not have been emitted "but for" the Rush Island performance improvements. Ameren—not Dr. Hausman—performed the engineering assessments of their outage work and folded those expected operational benefits into the company's modeling.[12] Dr. Hausman simply examined the result of those operational benefits on the units' projected operations. The

[11] These figures were based on Unit 1's partial outage rate results. Looking at Unit 2 or the forced outage rates would yield a smaller percentage triggering 40 tons of $S0_2$.

[12] Ameren argues that Dr. Hausman's with-and-without analyses are irrelevant because they do not compare baseline performance to projected performance. Rather, his analyses compare two future scenarios: the projected performance with the project to projected performance without the project. Although the comparison Dr. Hausman did is not the same as what is required of sources doing PSD calculations, Dr. Hausman's comparisons are relevant to this case, which requires a determination about causation. The purpose of Dr. Hausman's analysis was to examine the relationship between capacity and availability and that of generation and emissions. Conducting a with-and-without analysis provides useful causation information and is a standard industry method.

performance improvements Dr. Hausman identified in Ameren's ProSym input files are consistent with the performance improvements Mr. Koppe expected the Rush Island units would see over baseline levels based on his engineering analysis. The results of Dr. Hausman's analyses are summarized in the table below:

	Baseline Emissions	Modeled Performance Improvements	Projected Emissions	Total Increase	Result of Improvements
Rush 1	14,874 tpy	4.0% EAF	15,561 tpy	687 tons	562 tons
Rush 2	14,288 tpy	18 MW and 2.0% EAF	16,816 tpy	2,528 tons	746 tons

FOF 348–50, 353–54. These results show that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects.

Ameren's expert witnesses confirmed at trial that the technique Dr. Hausman used is commonly used in the industry. FOF 344. Ameren's experts Michael King and Marc Chupka testified that they had done or recommended similar analyses in prior PSD enforcement cases—but did not do them here. *Id.*

4. **The evidence shows that efficiency improvements would not prevent emissions from increasing as a result of the projects**

Ameren argued that it expected unit efficiency to improve at Unit 2[13] and that this efficiency improvement would offset any overall increase in emissions. Before this litigation, however, Ameren made clear that it expected the improved efficiency to result in *more*

[13] Ameren has also argued th at efficiency was expected to prevent an emissions increase at Unit 1. However, the project was not justified based on any efficiency improvements. It was justified based on outages and load limitations. FOF 145–47, 212. Moreover, while Ameren has now claimed some improvements in the unit's *net* efficiency, such an improvement means more of the unit's generation can be sent to the grid (as opposed to be used to run the plant itself) but does not reduce the amount of coal burned. FOF 117, 213, 351.

generation (greater total capacity) rather than less coal burned. In justifying the projects to management, Ameren's engineers predicted a small improvement (0.5%) in auxiliary load due to the boiler component replacements and a 15 MW increase in capacity due to the low pressure turbine. FOF 280. The 15 MW Ameren attributed to the turbine was *separate* from the 22.5 MW improvement attributed to the boiler components. Pl. Ex. 110; FOF 281. Similar improvements were reported by Ameren to the Missouri Public Service Commission—a 0.5% improvement due to the boiler component replacements and a 1.9% (12 MW) improvement due to the turbine replacement. FOF 291. Both types of improvements would result in producing more generation, but *not* in burning less coal. FOF 117, 213, 214, 280. Consistent with these reported expectations, Ameren did not incorporate *any* efficiency change in the 2010 fuel budget model run that it used as the projection for its NSR emissions calculation. FOF 401, 407. While Ameren later revised that run to reflect changed efficiency at Unit 2, it only did so *after* the project was long complete and the United States had filed this lawsuit. FOF 401. These revisions, which were made after the completion of the project and even after this lawsuit was filed, lack credibility. And even the revised projection showed an emissions increase that would trigger NSR after the analysis is adjusted to disregard Ameren's inappropriate application of the demand growth exclusion. *See* Subsection III.C.

The United States' experts took these potential efficiency improvements into consideration in performing their analyses. FOF 213–15, 279, 280, 300. Mr. Koppe explained that auxiliary load reductions would not impact gross efficiency, which is what matters for purposes of determining how much sulfur dioxide a unit will emit. FOF 117, 213. In his analysis of the turbine replacement at Unit 2, Mr. Koppe concluded that because the capacity increase at Unit 2 exceeded the efficiency improvement, the unit would ultimately still burn more coal even with the turbine replacement. FOF 214, 215, 280, 281, 300. Separately, Dr. Hausman did a variant of his with-and-without analysis that incorporated an efficiency increase that was even greater than the 2.4% improvement Ameren reported to the Missouri Public Service Commission. Dr. Hausman's analysis found improving efficiency had only a small effect on the projected increase related to the project, which was 696 tons of SO_2—still more than 15 times the threshold requirement. FOF 356.

Ameren concedes that efficiency actually got *worse* after the project compared to the baseline. Ameren blames a portion of the actual increase in pollution on the realized decrease in efficiency. Regardless of the cause for the unit's decline in efficiency, each hour of operations or each extra MW that is generated at the plant requires that much more coal—and results in that much more pollution. Ameren's argument has no impact on the United States' actual emissions theory because blaming increased emissions on unexpectedly declining unit efficiency does not change the fact that the units burned more coal and emitted more pollution than they otherwise would have without the boiler upgrades—and some of the emissions increase would never have occurred had Ameren decided not to perform those overhauls. Ameren did not claim that the efficiency decrease accounts for the entire post-project emissions increase. So even if some of the post-project actual increase was due to worsening efficiency, there was still an increase of emissions due to the projects.

Ameren argues that efficiency was *expected* to improve, so it was reasonable to expect less pollution, and then it argues that efficiency *actually* got worse, so the increase in pollution is unrelated to the projects. The evidence shows that the efficiency increase that Ameren claims to have expected would result in more MW, not less fuel burned. FOF 214, 215, 280, 281, 291, 300. And while the efficiency decrease that came after the project could explain part of the actual increase, it does not alter the fact that a substantial portion of the increase (far more than 40 tons) was related to the increased availability and capacity caused by the project. FOF 216.

5. Conclusion: The emissions evidence shows an increase related to the projects should have been expected and actually occurred

Ameren expected the projects to cause its highest period of post-project availability to rise well above the baseline availability for both units. The projects caused substantial availability increases. Ameren also expected and realized a post-project increase in capacity at Unit 2 from the challenged boiler work. Those expected and actual performance improvements were significantly larger than the small changes (an additional 21 full power hours or 1.7 MW) needed to cause a 40-ton increase in emissions.

The United States' experts approached the question of estimating the projected increases from different perspectives. Mr. Koppe and Dr. Sahu first focused on the expected incremental availability (and, for Unit 2, capacity) improvement, determined whether those improvements would be realized for the unit as a whole, and then directly calculated the tons of emissions associated just with those project-related improvements. Dr. Hausman took another approach. Using Ameren's modeling, he began with a projection that accounted for *everything* that Ameren expected at the units in the future, and then he isolated the amount of generation and pollution related to the project. Ameren criticized both approaches but never did its own calculation to show which of the additional tons of emissions were related to the projects.

Using these different approaches, Mr. Koppe and Dr. Sahu reached very similar conclusions to Dr. Hausman. Additionally, these experts' calculations were confirmed by the actual results, as shown in the two charts below:

UNIT 1	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	3.8%	4.0%	4.0%	4.3%
Δ SO_2	608 tons	562 tons	[No PSD Analysis]	665 tons
FOF	227, 232	348 – 350	228 – 231	238, 243

UNIT 2	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	2.8%	2.0%	3-4%	2.9%
Δ Capacity	18.1 MW	18 MW	22.5 MW	23 MW
Δ SO_2	415 (EAF) 417 (MW)	746 tons	2,531	2,170 tons
FOFs	251, 258, 303	353, 354	256, 276, 277, 402	260, 266, 300

The Koppe-Sahu results, Dr. Hausman's analyses, and the actual post-project data all establish that there is a significant net SO_2 increase of more than 40 tons that was caused by the projects. Based on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution. Ameren's model confirms that relationship, as Dr. Hausman showed and Ameren's chief modeler confirmed in his testimony. FOF 329–41, 448. Other courts have recognized this relationship. *See* Subsection II.B.1 above (citing cases). Ameren should have expected a significant net emissions increase and should have obtained a permit before beginning work.

C. Ameren Also Violated Title V

Because I conclude the projects were major modifications, I also find that Ameren has violated Title V of the Clean Air Act.

Title V creates an operating permit program designed to collect all of a source's applicable requirements under the Clean Air Act in a single place. 42 U.S.C. § 7661c(a); *Ameren SJ Decision*, 2016 WL 728234, at *3 (quoting *Sierra Club v. Otter Tail Power Co.*, 615 F.3d. 1008, 1012 (8th Cir. 2010)).

Missouri's Title V program requires sources to obtain a permit with "all applicable requirements." 10 C.S.R. § 10-6.065(6)(C)1.A; *see also* 42 U.S.C. §§ 7661 - 7661c(a). By definition, applicable requirements include requirements under the New Source Review program. 10 C.S.R. § 10-6.020(2)(A)23; *see also Ameren SJ Decision*, 2016 WL 728234, at *24. In addition, Ameren's Title V permit prohibits major modifications without Ameren first obtaining a permit. FOF 456.

By performing major modifications without obtaining an NSR permit (and satisfying the associated requirements, including the requirement to operate best availability control technology to reduce emissions), Ameren violated both the requirement to obtain a permit with all applicable requirements and the permit prohibition against unpermitted major modifications.

III. AMEREN'S DEFENSES AND CRITIQUES OF THE UNITED STATES' EVIDENCE FAIL

A. The Projects were not Routine Maintenance

Ameren has asserted the routine maintenance, repair, and replacement defense. The routine maintenance exemption provides that projects do not constitute "major modifications" if they merely consist of routine maintenance, repair, or replacement activities. *See* 40 C.F.R. § 52.21(b)(2)(iii)(a); 10 C.S.R. 10-6.060(8).

Based on the evidence presented at trial, I conclude that the projects cannot be considered routine maintenance under the law. The Rush Island boiler refurbishments at issue were the most expensive boiler projects ever performed on an Ameren boiler. FOF 182, 183. They involved the redesign and replacement of major boiler components that were intended to improve the performance of the units and enable them to burn coal they were not originally intended to burn. FOF 47, 53, 62, 134, 138–47. They were the first such replacements in the history of each unit, are rarely done at any unit in the industry, and the combination of boiler replacements has rarely, if ever, been done in the industry. FOF 172, 174–76. Under the appropriate legal standards, every factor of the routine maintenance test weighs heavily against classifying the work as routine maintenance, repair, and replacement. Even Ameren's designated expert on routine maintenance, Jerry Golden, acknowledged at trial that these projects were not *de minimis*. FOF 164.

1. Legal standard

The standard for the routine maintenance, repair and replacement exemption in the NSR rules "is a narrow one and is generally limited to *de minimis* circumstances." *Ameren SJ Decision*, 2016 WL 728234, at *5. Ameren has the burden of proving the routine maintenance exemption applies. *Id.*

As I explained at summary judgment, to determine whether a defendant has met its burden of proving the routine maintenance exemption, courts examine the projects, taking into account the 1) nature and extent, 2) purpose, 3) frequency, and 4) cost of the activity to arrive at a common-sense finding. *Id.* at *4, *5 (citing *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 910-11 (7th Cir. 1990)). "Frequency [is] evaluated by considering the work conducted at the particular unit, work conducted by others in the industry, and work conducted at other individual units within the industry. In evaluating frequency, the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, not how many similar projects have been implemented industry wide." *Id.* at *5.

EPA has consistently interpreted the routine maintenance exemption as requiring review based on the "principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine." *Id.* at *8. For these reasons, as I stated at summary judgment:

> separate equipment or component replacements should be taken as a whole, i.e., multiple component replacements may constitute one 'project,' for purposes of the RMRR analysis, if . . . it appears that the work was done as part of one project. Under this common sense framework, I agree with EPA that whether the challenged work was planned for together, budgeted together, performed together, and undertaken for the same purpose are relevant to the inquiry.

Id.

2. The boiler refurbishments at each Rush Island unit constitute one project for routine maintenance purposes

All of the boiler component replacements were related in that they were planned together, budgeted together as capital projects, performed at the same time, and undertaken for the same purpose. As a result, I find that the work should be viewed together in determining whether it qualifies for the routine maintenance exemption.[14]

<u>The work was planned together.</u> There is no question that Ameren planned the component replacements together. When Ameren issued the contract documents to qualified bidders for the project, it consolidated all of the work in its contract specifications. FOF 133, 134. Ameren noted that the projects were combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacement as "part of a Major Mechanical

[14] Even if I were to consider each major component replacement separately, I would still conclude that the projects were not routine maintenance under the weight of the evidence.

Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler."

FOF 132. Ameren described the "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nea rly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater—redesigned for PRB coal
> - Economizer—redesigned for PRB coal
> - Lower Slope—ruggedized design to better withstand slag falls
> - Air Preheater—redesigned for ease of future basket replacement.

P. Ex. 6; FOF 139.

The work was budgeted together. As of December 2004, Ameren had created a preliminary capital budget for the replacement of the Unit 1 economizer, reheater, lower slopes, and air preheater as part of a single project. FOF 126. Even though Ameren prepared separate work orders for the two air preheater replacements, all the work was from Ameren's capital budget—not the operations and maintenance budget—and was budgeted for the same outage to be performed at the same time. FOF 130, 131, 181. Likewise, at Unit 2, Ameren consolidated the replacement of the challenged components when it sought bids from outside engineering firms to design, fabricate, and install those components. FOF 133.

The work was performed at the same time. It is undisputed that the components at issue were performed together during the same outages at Unit 1 and Unit 2. FOF 25, 169, 170.

The work was undertaken for the same purpose. Ameren's routine maintenance expert, Mr. Golden, agreed that the purpose of the work at each unit was the same. FOF 150–51. Mr. Golden confirmed Mr. Stevens' testimony that the purpose of the work at each unit was to eliminate pluggage and fouling of the economizers and reheaters and to eliminate future forced and maintenance outages caused by tube leaks.[15] FOF 56–69, 145–47, 149. The United States' expert Mr. Koppe also explained that Ameren could completely resolve the capability restraints caused by pluggage only by replacing each of the components at issue during the same outage. FOF 53, 63, 196. Ameren's Jeff Shelton agreed. FOF 64.

3. The projects do not qualify for the routine maintenance exemption

a. Nature and extent

The 2007 and 2010 projects involved the replacement of major boiler components that are integral to the operation of the Rush Island Unit 1 and 2 boilers. The 2007 and 2010 projects took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. FOF 139, 164. The projects were far more extensive than the type of maintenance, repair, and replacement routinely performed at Rush Island and other coal-fired power plants. FOF 165–72. And it is clear from Ameren's documents that the company itself never considered these projects to be just "routine maintenance," as that term is understood in the industry; it considered them to be "major boiler modifications" or "major boiler refurbishments." FOF 50, 130, 139, 171.

Each of the boiler components was redesigned to eliminate the recurring problems associated with Ameren's switch to PRB coal. FOF 53, 134, 138–49. These design changes were intended to upgrade and improve the performance of the boilers. FOF 145–60.

Given the complexity of the replacements, the components were designed, engineered, and constructed by outside contractors, such as Alstom Power, the original manufacturer of the boilers. The work was well beyond the capacity of Ameren's own staff. FOF 128, 166.

[15] On Unit 1, the lower slopes were replaced to eliminate tube leaks and repair damage resulting from slag falls and erosion following the switch to PRB coal. FOF 52, 53, 56–59.

In contrast with routine maintenance, repairs, and replacements undertaken at utility plants, the projects required approvals of executives at the very highest level of the company, including Ameren's CEO. FOF 135–37.

The economizers, reheaters, and air preheaters each weigh hundreds of thousands of pounds and required construction of heavy equipment such as monorails and cranes. FOF 162, 167–68.

The 2007 outage for Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. FOF 169. Ninety-one percent of the work done during the Unit 1 outage was performed by contractors. *Id.*

The 2010 outage at Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. FOF 170. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. *Id.*

The 2007 and 2010 overhauls were considered capital projects and were funded out of Ameren's capital budget rather than the operations and maintenance budget. FOF 181. As capital projects, these component replacements improved the value of the generating unit. FOF 180.

As a result, the nature and extent of these projects weighs heavily against a finding that these projects qualify for the narrow routine maintenance exemption.

b. Purpose

As noted above, the consistent purpose of the projects was to eliminate pluggage, fouling, and tube leaks. Ameren expected that tube leaks in the economizers and reheaters would be eliminated for at least 20 years. FOF 38, 145–47. By contrast, routine maintenance, repair, and replacement is performed to allow a unit or plant to continue to operate in its present condition.

See Doc. 227-2, Memorandum from Don Clay, Acting EPA Ass't Admin. (Sept. 9, 1988), at 3-4; Doc. 227-3, 2000 DTE Applicability Determination Detailed Analysis, at 11.

The replacement of these major boiler components allowed the units to operate hundreds more hours than they could in the baseline period at a higher capacity by eliminating tube leaks, load limitations, and operational constraints. The purpose of these projects indicates that the work was far from routine.

c. Frequency

Even though the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, for each of the three inquiries under the frequency factor, the inquiry weighs heavily against a finding of routineness.

<u>Frequency at the unit.</u> None of the components at issue had been replaced at these units before. FOF 173. The components were replaced after 31 years of service at Unit 1 and 33 years of service at Unit 2. FOF 4, 174.

<u>Frequency at individual units within the industry.</u> The components at issue are very rarely replaced at any plant. FOF 174–76. Ameren's expert confirmed this point. Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of the lower furnace is about 40 years. FOF 174. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. *Id.* This evidence, coming from Ameren's expert, demonstrates that replacing the components at issue is rarely done at individual units within the industry.

<u>Work conducted by others in the industry.</u> Mr. Golden testified about a list he has complied of 18,300 projects undertaken at coal-fired power plants. The list includes projects that

Mr. Golden identifies as capital projects costing more than $100,000. *Id.* As an initial matter, the relevance of Mr. Golden's list to this case is weak because Mr. Golden has been unable to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. *Id.* Boiler refurbishments like the ones at Rush Island are not common in the industry.

Regarding air preheater replacements, Mr. Golden identified 35 replacements of regenerative air preheaters going back to the 1970s.[16] FOF 176. By his count, that is less than 2 percent of the coal-fired units in the country. However, Mr. Golden was unable to say whether those 35 instances were complete replacements or similar to those at Rush Island. *Id.* Even if they were, a replacement that takes place at less than 2 percent of the units going back to the 1970s is not common in the industry.

As a result, the frequency factor weighs heavily against these projects being routine.

d. Cost

The projects at issue were the most expensive capital projects ever done at Rush Island. Each project cost substantially more than the entire operations and maintenance budget for the plant for an entire year. FOF 177, 178, 182. Grouping the replacements at each unit together, the two projects were among the most expensive boiler projects ever undertaken at any of Ameren's plants. FOF 183.

Based on the undisputed facts regarding the costs of these projects, the cost factor also weighs heavily against these projects being routine.

4. Conclusion: the projects cannot be considered routine

[16] Even for the claimed 35 air preheater replacements, Mr. Golden was unable to testify that all were complete replacements or that all the replacements were comparable to the air preheater replacements at Rush Island. FOF 177.

Ameren has not satisfied its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the "most significant" outages in plant history. FOF 172. A common sense finding weighing the nature and extent, purpose, frequency and cost of the projects reveal them to be far from *de minimis* activities contemplated by the exemption. Ameren's expert agreed and testified at trial that these projects were not *de minimis* activities. As a result, Ameren's routine maintenance defense fails.

B. The Emissions Increases Cannot Be Set Aside Based on the Demand Growth Exclusion

Ameren also asserts the "demand growth exclusion," set forth at 40 C.F.R. § 52.21(b)(41)(ii)(c), as a defense to liability. As the United States Court of Appeals for the District of Columbia explained in *New York v. EPA*, "the regulation establishes two criteria a source must meet before excluding emissions from its projection: (1) the unit could have achieved the necessary level of utilization during the [baseline period]; and (2) the increase is not related to the physical or operational change(s) made to the unit." 413 F.3d at 33 (quotations omitted). "The two prongs are distinct. Satisfying the 'could have accommodated' prong is necessary but not sufficient to justify application of the exclusion, and emissions that 'could have been accommodated' at baseline are not per se 'unrelated.'" *Ameren SJ Decision*, 2016 WL 728234, at *21.

Additionally, as stated at summary judgment, "the burden is Ameren's to prove that the demand growth exclusion applies." *Id.*

1. Ameren's experts confirm that demand was not projected to—and did not—cause the pollution increases at Rush Island

Fundamental to an invocation of the demand growth exemption is that demand *on the unit* increases. But in this case just the opposite happened, as the data shows—and Ameren's expert witnesses conceded.

A unit's "utilization" is a measure of how much of its available capacity the unit is called on to use. The measure serves to reflect market demand on a specific unit. FOF 377. As Mr. King explained, a declining utilization factor means demand on the unit is decreasing. FOF 378. As a result, when the utilization factor is declining, an increase in pollution *cannot* be the result of demand. *Id.*

As far as the actual emissions case is concerned, Mr. King and Ms. Ringelstetter both testified that the utilization factor for the Rush Island units actually *decreased* after the projects. FOF 378–80. The declining demand that the units actually experienced after the projects prevents Ameren from asserting a successful demand growth argument for the actual emissions increase shown in the data.

Ameren's application of the demand growth exclusion also fails for the expectations case. Ameren's testifying expert Marc Chupka looked at the utilization factor data leading up to each project and concluded that "[i]t would be reasonable to assume a constant utilization factor for projecting future emissions" following the boiler upgrades at issue in this case. FOF 208. Ms. Ringelstetter agreed. She testified that the utilization of Unit 1 was projected to remain basically constant, and, though utilization of Unit 2 was projected to increase somewhat (about 2%), the increase paled in comparison to the projected increase in emissions (over 15%). FOF 380. A constant utilization factor means static demand on the units. If that demand is constant, it cannot be the cause of an emissions increase. Regardless, even the marginal projected increase in Unit 2's utilization factor cannot account for the substantial emissions increase that Ameren's modeling and calculations projected. *Id.*

2. Ameren's evidence does not address what portion of the units' projected or actual emissions increases were "unrelated" to the projects

The evidence Ameren presented in support of the demand growth defense generally falls into two categories: (1) evidence that regional demand for electricity was generally going up during the years surrounding the Rush Island projects, and (2) calculations regarding how much generation (and pollution) the units "could have accommodated" during the baseline periods. The central problem for Ameren's defense is that these showings, while necessary to the company's proof, are insufficient to establish that the demand growth exclusion applies to any specific "portion" of its projected emissions increases, as required by the rule. *Cf.* 40 C.F.R. § 52.21(b)(41)(ii)(*c*); *see also* 40 C.F.R. § 52.21(r)(6)(i)(*c*) (requiring operators to document and describe certain PSD analyses, including "the amount of emissions excluded under [the demand growth exclusion] and an explanation for why such amount was excluded"). Ameren has failed to establish a correlation between rising regional demand and any specific impact on unit performance in order to show what portion of its projected emissions increases are "unrelated" to the projects at issue in this case.[17]

[17] Ameren's theory on demand growth appears to be that, if it can prove emissions were related to demand, then the emissions cannot be related to the projects. This rests on the false assumption that an effect can only have one cause. Because pollution, like any effect, can have more than one "but for" cause, it is not enough for Ameren to simply point out that some of its projected and actual increases in emissions are related to the presence of sufficient market demand for Rush Island power. Ameren disputes the relevance of the restaurant analogy argued by the United States and used by the Court at summary judgment. *See Ameren SJ Decision,* 2016 WL 728234 at *10 n.17. But the restaurant analogy remains useful. To be sure, a meal

The first category of Ameren's evidence—its various system load forecasts—fails to connect meaningfully to projections of unit operations because increases in system demand do not necessarily translate into increases in unit operations. As Ameren's witnesses testified, during the baseline period, the units operated as baseload units and operated whenever they were available. As a result, they were usually fully-loaded during "on peak" hours when system demand was at its highest. FOF 371–72. If the units were generally maxed out anyway, increases in system demand would have little effect on unit operations.[18] That is reflected in Ameren's expert testimony on unit utilization, discussed above. Moreover, as Dr. Hausman testified, Ameren's ProSym modeling efforts showed just how disconnected unit operations were from system level demand. Ameren's load forecasts were inputs into its modeling runs, and they reflected the company's expectation that system load was growing on the order of 1% a year. But the output files from those very same runs reveal Ameren's computer simulations projected that generation from the Rush Island units would increase immediately following the outage and then remain relatively flat. FOF 373. Ameren seems to suggest that rising regional demand for electricity—like a rising tide—would lift operating levels at its units. The evidence clearly establishes otherwise.

---

served to a restaurant customer is "related" to the customer's decision to order it (customer demand); but that does not mean that the meal is "unrelated" to the restaurant having an open table or the chef's preparation of the food.

[18] Ameren witness Jaime Haro noted that, for baseload units like Rush Island, increases in system demand would mean the units still ran at high levels most of the day, but they might ramp down a little later each day or turn up to full load a littl e earlier each morning. FOF 370 . The marginal increases in demand on the "shoulder" hours may have been attributable to system level demand, but Ameren made no attempt to quantify just what portion of its emissions projections were made up of these marginal shifts . As a result, Ameren cannot meet its burden of proof on this defense.

Ameren's second category of evidence, presented through its expert Sandra Ringelstetter, is a series of calculations describing how much SO_2 pollution the Rush Island units "could have accommodated" during their respective baseline periods. This, too, fails to address how any specific portion of its projected emissions increases is unrelated to the projects at issue. It does not address any portion of the units' projected emissions *at all*. While varying somewhat in the details, all of these calculations involve picking a pollution rate the units achieved at some limited point during the baseline period (sometimes a month, sometimes a week, sometimes a discontinuous set of hours taken from across the 24-month baseline period), and then multiplying that emissions rate by the unit's baseline equivalent availability levels. Since EAF is a measure of available hours, and since its emissions rate is related to a unit's load levels,[19] these calculations essentially assume that the unit would run flat out, at some very high level of operations, through day and night, for nearly two continuous years. Ameren then concludes that, since demand was going up and its "could have accommodated" calculations result in more emissions than any projected increase in this case, *all* projected emissions increases can and should be excluded from the NSR liability calculation.

Ameren's "could have accommodated" calculations are fundamentally flawed. For example, they employ unreasonably-high emissions rates and rely on applicability determinations divorced from the operational realities of electric utilities. But even if Ameren's "could have accommodated" calculations were reliable, the calculations cannot—as a structural matter—say anything about whether the projected emissions from the units are *related* to the projects at hand. Ameren's "could have accommodated" calculations consider neither the

[19] Despite Ms. Ringelstetter's testimony to the contrary, hourly emissions are directly related to hourly heat input in her own analysis, Ringelstetter Test., Vol. 11 -B, 85:15–86:3, and the relationship between heat input and unit load level is "more or less linear." *Id.* at 85:9 – 11.

projects at issue nor the projected emissions in any way. At best, the calculations have something to say about only one prong of the demand growth exclusion, which is not sufficient to establish the exclusion applies.

3. Ameren's other demand growth arguments fail

Ameren made two additional arguments at trial in support of its demand growth defense. First, Ameren argued that "unit-level demand" is not the focus of the test, and that instead, the demand growth exclusion focuses directly on "systemwide demand." In other words, Ameren argues that the problem of translating system demand into demand on the unit and changes in unit operations is not required by the rule itself. For that proposition, Ameren cites the 1992 WEPCO Rule Preamble where the demand growth exclusion was first introduced. The passage does not support Ameren's argument; in fact, just the opposite:

> [W]here increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and *affected the unit's operations* even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions.

57 Fed Reg. 32,314, 32,326 (1992). As a result, the regulations themselves establish that EPA has always required an operator to show whether—and to what extent—demand would "affect the unit's operations" before the demand growth exclusion could be applied.[20]

[20] Ameren cites various other authorities in its post-trial brief to support its argument that evidence of increasing systemwide demand is sufficient to establish the demand growth exclusion. Ameren misreads each of these authorities, ignoring paired language clarifying that the relevant inquiry requires consideration of how demand affects the units at issue. The demand growth standard is clear. In situations like these, "where [a] proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996).

Ameren's second argument was presented through the testimony of Ms. Ringelstetter. Specifically, Ameren argued that any performance changes or any emissions increases following the Rush Island modifications would be unrelated to those boiler modifications. This conclusion is unsupported and was offered for the first time at trial.

Until the summary judgment ruling, Ameren and its experts declared that it did not really matter *what* the project was so long as the unit, during the baseline, "could have accommodated" the projected emissions. As the head of Ameren's Environmental Services Department testified in Rule 30(b)(6) deposition testimony, "The emissions that the unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Depo. Test. 38:4-12; *see also Ameren SJ Decision*, 2016 WL 728234, at 9 (describing Ameren's argument that "'unrelated' means any emissions increases a unit could have accommodated at baseline"). And when Ms. Ringelstetter originally performed her "could have accommodated" calculations, she declared that was the only step necessary to establish that the exclusion applied. She testified at her deposition that even assuming the performance improvements she recognized in Ameren's modeling files were the result of the boiler upgrades, it would not have changed her analysis, her calculations, her considerations, or her conclusions in any way. FOF 438.

Ameren's theory is inconsistent with the plain language of the regulations, the case law, and my summary judgment decision holding that the two prongs of the exclusion are distinct. *See Ameren SJ Decision*, 2016 WL 728234, at *11. After my summary judgment ruling, Ameren adjusted its theory and attempted to show that neither the capacity increase experienced at Unit 2 nor the availability increase experienced at either unit was related to the boiler upgrade work at issue in this case. Not only is such a conclusion contrary to the Ameren's internal engineering and economic documents, the pre- and post-project analyses provided by Ms. Ringelstetter, on which Ameren bases its relatedness arguments, are flawed.

Ms. Ringelstetter's capacity analysis begins by relying on inapplicable pre-project values. Instead of comparing projected future operations to actual, past operations, she looks at modeling inputs from previous years. Though those earlier modeling efforts might generally be expected to reflect the unit's actual operations around that time, the capacity values used here present a particular problem: Ameren uses its capability tables to develop unit capacity inputs, and for half of the baseline at each unit, the capacity tables were "unrealistically high."[21] FOF 431–32. That means the capacity increase Ameren expected to see and did see following the Unit 2 work was about twice what Ms. Ringelstetter saw. That increase cannot be attributable to turbine work alone, as Ms. Ringelstetter claims. FOF 431–32; *cf.*, *e.g.*, FOF 304.

Ms. Ringelstetter's analysis also discounts the observed availability increases post-project as being too small to be meaningful. Essentially, Ms. Ringelstetter argues that the increases are "in the noise," so there is no increase at all. But the evidence shows that just a 0.3% availability improvement could result in 40 additional tons of SO_2 at Rush Island. FOF 191. Ameren's

[21] In January and February of 2006—and in middle of the baseline periods—Ameren decided to update its capability tables to come up with more accurate predictions. Pl. Ex. 157 at AM-02743289. For the Rush Island units, that meant substantially reducing the projected unit capabilities as operating data showed that the units were struggling to perform as expected for many months of the year. U.S. FOF 119. Recognizing this, and using "historical operating data along with design criteria," Ameren updated its capability tables and substantially reduced the Rush Island numbers in order to "generate more realistic capability ratings for all of [the company's] fossil units." Pl. Ex. 260 at AM-00091465. The new numbers dropped the average annual capability ratings for the units by about 12 MW. Compare Pl. Ex. 157 with Pl. Ex. 260. So Ms. Ringelstetter's baseline capability number is substantially inflated since almost half of the numbers there were "unrealistically high." U.S. FOF 432.

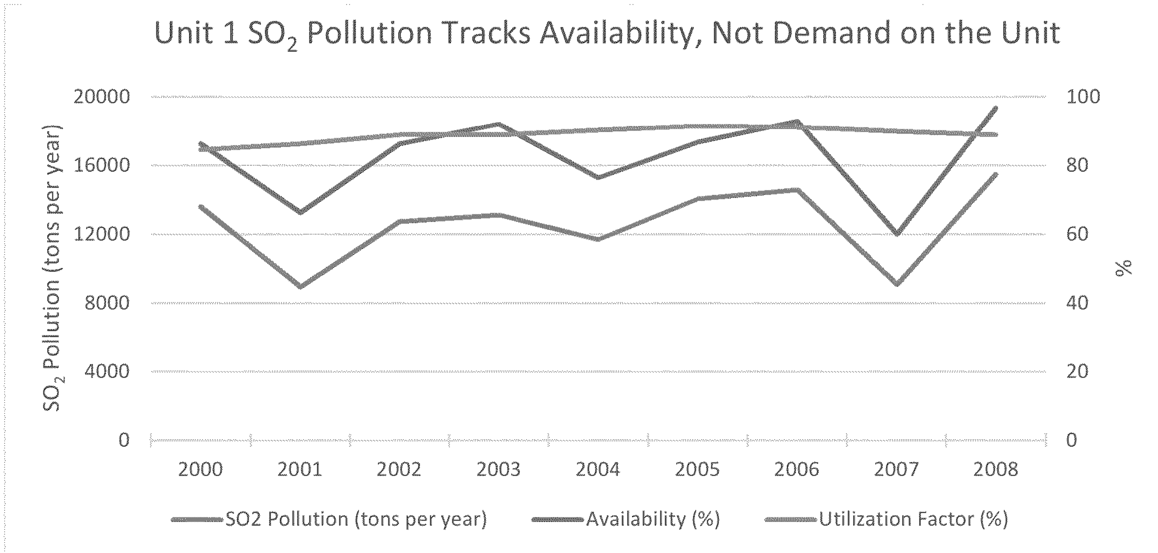
economic justifications were calculated to a tenth of a percent. FOF 104, 148. Ms. Ringelstetter's opinion also disregards the fact that Ameren projected long-term averages in its computer modeling and that specific years, as is relevant under the PSD analysis, might be as much as 2% or 3% higher than the inputs presented in the ProSym inputs. FOF 257. The important inquiry here is the size of the availability gain, which the evidence noted in Subsection II.B has shown to be about 3–4%. As Dr. Hausman testified, that kind of gain would lead to additional operations and pollution. To the extent Ms. Ringelstetter's testimony disregards these gains, her testimony is simply not credible.

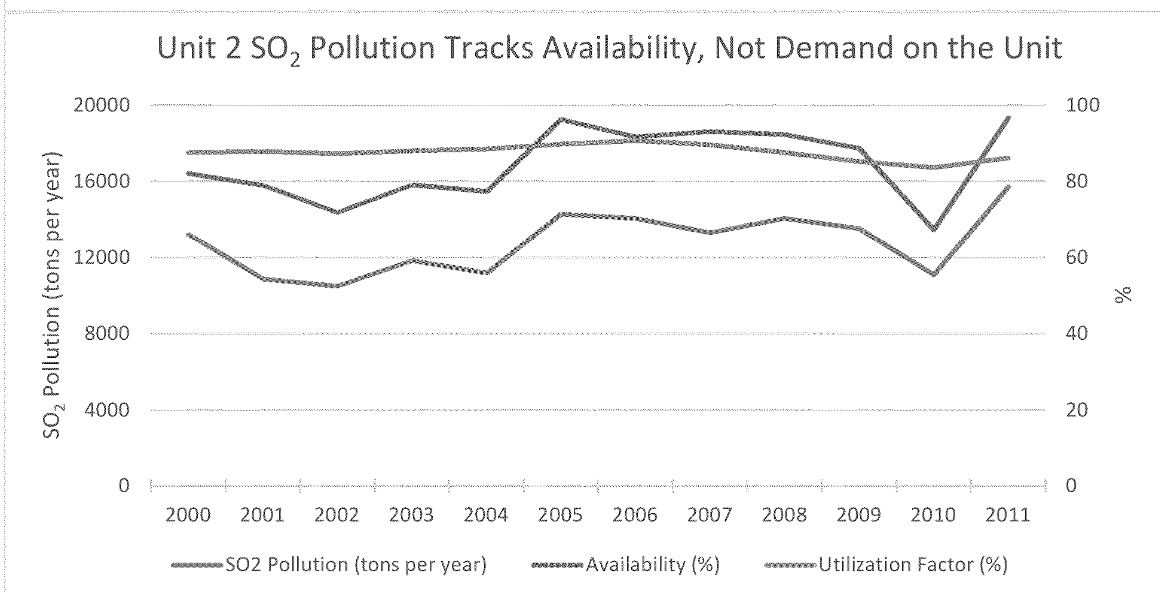
4. Emissions resulting from operations that would not have been possible but for the boiler upgrades cannot be considered "unrelated" to those boiler upgrades

Ameren's demand growth defense fails to address whether projected emission increases are related to the projects at issue. No matter how Ameren calculates the quantity of emissions it could have emitted had demand for electricity stayed high through the night, it does not address the reality that the units' real opportunities to sell more (and emit more) came by expanding their ability to operate when the demand is high—and when their units are generally maxed out—during the day. FOF 370–71. If there were baseline hours where the unit could not operate because of outages caused by the components at issue, any post-project recovery of those hours would be related to the project. Mr. Koppe found there were 246 outage hours for Unit 1 and 146 outage hours for Unit 2 caused by the projects in the baseline. FOF 240, 263. As described in Subsection II.B of my Conclusions of Law, both Mr. Koppe and Ameren concluded that those hours would be recovered and used in the post-project period. For those hours, the units went from unable to operate to able to operate. Demand did not cause that change; the units already operated every hour they could. That change resulted from $70 million of capital work. As I explained at summary judgment, when a unit "undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification." *Ameren SJ Decision*, 2016 WL 728234, at *10.

Ameren's witness admitted that changes in unit capacity or availability would lead to changes in operations and pollution, FOF 427–28, and the company justified the cost of the projects on precisely those kinds of performance improvements. FOF 146, 277. Dr. Hausman specifically examined how performance improvements at the units translate into coal consumption and pollution, and the result is predictable: when the units are better able to supply electricity, they do so, and they burn more coal in the process, emitting more pollution. *See* Subsection II.B.2.c.

Moreover, the company's data reflects the straightforward relationship between the Rush Island units' performance abilities and their pollution levels. As discussed earlier, "[u]tilization is a variable that describes how much of the [unit's] available capacity the unit utilizes," and that in turn reflects the influence of all of the "market considerations" like system demand and market price that can impact unit operations. FOF 377. A unit's equivalent availability factor, on the other hand, reflects the engineering condition of the unit—how well it has been maintained and whether it stands ready to generate whenever needed. FOF 94. The graphs below show that Ameren's historical emissions data reflects the reality that Rush Island operations were driven by its engineering condition (measured by its availability) more than any market fluctuations (measured in its utilization). These graphs show SO_2 emissions, availability, and utilization factor at Units 1 and 2, respectively. They were the subject of testimony by Dr. Sahu and Mr. King and are based on data compiled by Dr. Sahu and Ms. Ringelstetter.[22]





[22] Ameren moved to exclude the graphs as not properly disclosed. For reasons I discuss below (*see* Section on Evidentiary Issues), I will deny Ameren's motion as it relates to these graphs. Notably, the charts were also used in the United States' summary judgment briefing, Doc. 609 at p. 20, and Ameren's David Strubberg presented a similar chart, comparing availability and generation, at the 2008 State of the System Meeting. FOF 202.

Reviewing these charts at trial, Ameren's testifying expert Michael King conceded that there was a relationship between availability and pollution. FOF 381.

Ameren argued that being forced to translate system level demand into an effect on unit operations would turn the analysis from an annual emissions focus to an hour-by-hour assessment, which is not contemplated by the regulations. That argument fails for two reasons.

First, just as a restaurant owner knows the ebb and flow of customers throughout the lunch and dinner rushes, Ameren knew that Rush Island generally ran hard throughout the day and ramped down somewhat at night. In this context, Ameren's employees noted that derates resulting from pluggage in the units' boiler components were costing the company as much as $25,000 a day. FOF 112. A company does not lose earnings when it has available capacity that it could dip into at a moment's notice; it loses earnings when it cannot provide the generation it would otherwise be able to sell for a profit. *See, e.g.*, FOF 112, 274 (Williamson email). And when Ameren justified the substantial expense of the boiler overhauls at the Rush Island units, the company quantified the benefit of recovering availability and capacity. Again, those benefits can only be considered "benefits" of the projects if the units would not have otherwise been able to operate that often or at those levels. *See*, *e.g.*, FOF 146. Documents like these reflect the general truth—without necessitating an hour-by-hour data review—that the units were limited, the problems were expected to be fixed, and the units would operate more as a result.

Ameren's argument that NSR cannot require sources to perform an hour-by-hour look at operations is disingenuous when its own ProSym software—which it uses regularly in the course of its business and runs hundreds if not thousands of times each year—solves the dispatch problem on an hour-by-hour basis for every year it is told to do so. FOF 317. That model makes it easy to isolate how performance improvements would interact with other market constraints to determine unit operations on an hour-by-hour basis and further determine how those hourly operations translate into annual generation and pollution numbers. Dr. Hausman did just that, and the results showed a straightforward relationship: more capacity or more availability led to more generation and more pollution. PSD requires sources to consider "all relevant information" in analyzing whether emissions will increase; it does not contemplate sources ignoring known, relevant information just because it might be unfavorable. Section 52.21(b)(41)(ii)(a). Ameren had the relevant information, and that information showed that the Rush Island units' performance would improve, resulting in increased generation and emissions.

As I have previously ruled, increases made possible by performance improvements must be attributed to the project and cannot be covered by the demand growth exclusion. *See* Subsection II.B.1.

C. Ameren's New Source Review Analyses Are Fatally Flawed and Cannot Provide Safe Harbor from Liability

Ameren's emissions calculations are not reasonable analyses under the PSD rules and therefore do not show that Ameren should not have expected an emissions increase.

1. Ameren does not have a legitimate process for assessing PSD applicability

First, Ameren's position relies on a fundamental misunderstanding of the PSD program. Ameren offered the testimony of Mr. Boll and Mr. Whitworth at trial to describe how Ameren determined whether a project might cause an emissions increase. Both witnesses testified that the company looked to whether the unit's *potential* emissions were expected to increase.[23] FOF 391. The company employee actually charged with performing the PSD analysis for Unit 2

[23] Mr. Boll used the term maximum continuous rating. FOF 391. As Ameren explained in its earlier briefing, that term is a measure of a unit's potential emissions. Doc. 542 at 5-6.

confirmed Ameren's reliance on the wrong metrics when he testified that any improvements in availability were "irrelevant." FOF 396, 397(d).

Ameren's method of assessing PSD does not comply with the rules, EPA's instructions, or case law. The rules explicitly direct a source to compare projected emissions to baseline emissions, both measured in tons per year. 40 C.F.R. § 52.21(b)(41), (48). As noted above, both EPA and the courts that have interpreted the PSD program have explained that "[i]f an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5. EPA has brought enforcement actions since 1999 based on improvements in availability that lead to increases in annual pollution. Ameren's testifying expert conceded that EPA's enforcement approach has been "well-known in the industry" since 1999. FOF 219.

By focusing on potential emissions, Ameren ignores my ruling on Ameren's first motion for summary judgment. In motions practice, Ameren argued that the United States had to show a "modification" under the Missouri SIP before turning to the issue of whether the projects were "major modifications." Doc. 542 at 1-2. Ameren argued that modification status was controlled by *potential* emissions. *Id.* I rejected that argument. Doc. 711. As Ameren argued at summary judgment, "'modification' and 'major modification' are distinct terms with separate characteristics under the SIP." Doc. 542 at 5. At trial, however, Ameren described its internal analysis as focused solely on the first test, not the major modification test actually before the Court.

For the reasons described in Subsection II.B.2 of my Conclusions of Law, if Ameren had considered how the actual performance changes would affect generation, it would have expected and found emissions increases related to the project.

Second, Ameren failed to coordinate between the engineers who planned and performed the projects and the environmental services employees charged with assessing NSR applicability. Michael Hutcheson, who performed the NSR analysis for the Unit 2 project, reported that he learned about the project from his boss and his boss's boss but never talked to the engineers working on the project. FOF 397(a).

On the other side of this divide, engineering leaders at Ameren like Robert Meiners and David Strubberg testified that they had no involvement in assessing whether the projects triggered PSD. FOF 393. Mr. Meiners testified that as plant manager, he was "accountable" for ensuring that Rush Island complied with environmental regulations. *Id.* Despite that accountability, Mr. Meiners testified that he had never been involved in a single discussion about whether to seek a New Source Review permit for any project:

> Q. Even though you were plant manager, though, you had no involvement at all in the decision of whether to seek a New Source Review permit for either of the projects at issue in this case, right?
>
> A. I was not involved with that. We had an environmental department that took care of those kind of items. I was not involved.
>
> Q. And by "not involved," I mean, you didn't have a single discussion with anyone about the decision of whether to seek a New Source Review permit?
>
> A. No, I did not.
>
> Q. And, in fact, throughout your career at Ameren you've never had a single discussion with anybody about whether to seek a New Source Review permit for any project, right?
>
> A. No, I have not.

Tr. Vol. 7-B, 64:6-20.

The project justification packages that Ameren regularly put together as part of the work approval process included a checkbox asking whether the proponent had assessed

"Legal/Environmental" risks. FOF 388. But as one engineering manager testified, he could not "recall that box ever being checked" and had no idea what it meant. FOF 389. Each project had to be approved by a series of managers and executives, even the company CEO and board of directors. FOF 135–37. But the Environmental Services Department, charged with assessing NSR applicability, was not asked to approve the projects.

As a result, Ameren's PSD process suffered from two major flaws: the employees charged with assessing applicability started with an incorrect understanding of the law and lacked a meaningful understanding of the facts of the projects. In addition to these procedural flaws, for the reasons that follow, the actual analyses Ameren did "conduct" (for Unit 2 only) provide no basis for finding that Ameren could have reasonably expected the project would not significantly increase net emissions.

2. Unit 1

Ameren concedes that it performed no numerical calculation for the Unit 1 project.[24] FOF 391. Whatever qualitative analysis may have been done at the time cannot shield Ameren from liability now. Nor can the post-hoc analysis offered at trial by testifying expert Sandra

[24] Ameren argued for the first time in its post-trial brief that it was not required to perform a numerical calculation at Unit 1 because the provision of the 2002 Reform Rules requiring such calculations be performed was on remand at the relevant time. Ameren's argument fails. Even though a portion of the rule was on remand at the time, the Missouri SIP and EPA still required sources to maintain these records. *See* 71 Fed. Reg. 36,486, 36,487-88 (June 27, 2006); *see also* US Resp. Br. (Doc. 838) at 47-48. Moreover, as Ameren itself points out, the United States has not brought a record-keeping case and is not seeking judgment that Ameren failed to maintain the necessary records. Rather, the relevant issue is whether Ameren reasonably should have expected emissions to increase because of the projects. Whether Ameren performed a numerical calculation at all is certainly relevant to that inquiry and will, accordingly, be considered.

Ringelstetter, who used an inapt modeling run and incorrect application of the demand growth exclusion.

As an initial matter, there is no contemporaneous evidence that Ameren performed any assessment of the Unit 1 project. Mr. Boll testified that Ameren performed a qualitative emissions analysis for the projects in 2005. FOF 390, 391. But this analysis did not even rise to the back-of-an-envelope level—there is no written record of any such analysis. Moreover, because Mr. Boll and Mr. Whitworth made clear they only considered the maximum continuous rating of the unit, any qualitative analysis they did "conduct" did not comply with NSR requirements and therefore was not reasonable under the law. *Id.*

The post-hoc analysis performed by Ms. Ringelstetter does nothing to support Ameren's belief that emissions would not increase at Unit 1. Despite presumably having access to scores of ProSym modeling runs that projected Unit 1's post-project operations, Ms. Ringelstetter selected a run with two key flaws. First, according to her trial testimony, the run actually overstated emissions, so she adjusted it downward. FOF 454. Notably, other runs had no such issue, and Ameren itself never saw the need to adjust the run. FOF 454. Second, the run intentionally depressed output from Unit 1 for the full five years following the project based on the potential for the unit to provide ancillary services.[25] FOF 448, 449, 453. Ameren did not provide any evidence to support this assumption other than the testimony of Ms. Ringelstetter herself. Ms. Ringelstetter testified the modeling assumption was "entirely appropriate" and yet did not offer any document or specific fact to support that conclusion. She never even

[25] Ancillary services are services other than simple electric generation that utilities provide to keep the electric grid operating reliability. FOF 439.

mentioned ancillary services, spinning reserves, or regulation hours in her expert report. FOF 451. Moreover, the limited evidence in the record contradicts her opinion:

1. The only evidence that Ameren may have expected to provide some ancillary services with the Rush Island units around the time the boiler upgrades were performed is a short-term contract between Ameren Missouri and its Illinois affiliates. But that contract does not require anything specific of the Rush Island units in particular; in fact, it gave Ameren Missouri flexibility to provide the services from a number of different units. FOF 442.

2. Whatever effect the contract may have had on operations of the Rush Island units, the effect was never expected to last. The contract was never intended to extend beyond the inauguration of MISO's regional ancillary services market (originally scheduled in 2008 and then delayed to January 2009). FOF 440. Ameren's witnesses all agreed that once MISO implemented its ancillary services market the Rush Island units would not be providing such services at it does not make economic sense to hold back such cheap, reliable sources of generation. In fact, Ameren's head modeler told the Missouri Public Service Commission in that it did not make sense to model those services because they were based on a "short-term contract that will end when the MISO ancillary service market begins." FOF 445.

Selecting a run which depressed output for five years by modeling ancillary services at the Rush Island Unit 1 that—if ever they had an impact on operations—would last no more than two years after the project runs afoul of the regulations' requirement to "consider all relevant information" and use the highest year of post-project emissions. 40 C.F.R. § 52.21(b)(41)(ii)(*a*).[26]

3. Unit 2

While Ameren did at least perform numerical analyses for Unit 2, these analyses are no more compelling than its qualitative analysis for Unit 1.

As an initial matter, even though PSD analyses should be completed before beginning construction, Ameren did not complete any numerical analysis for Unit 2 until after the project work started. FOF 398-401. Ameren began its "Original" analysis at the end of 2009, which

[26] After using an inappropriate modeling run to obtain projected emissions, Ms. Ringelstetter misapplied the demand growth exclusion, as described in Subsection III.B of my Conclusions of Law.

relied on a January 2010 modeling run. By the time that analysis was done, the project was underway and it was too late for Ameren to comply with the law if a permit was required. Moreover, the work had been *approved* for four years at that point. The work was first approved in 2005 and then reassessed in a process that culminated with the final approval from the Board of Directors in August 2009. FOF 400.

Mr. Hutcheson testified at trial that the Original Unit 2 emissions calculation was one of about two dozen requested at the same time by Ameren's legal department. FOF 399. The projects to be assessed were a mix of past and future projects. *Id.* For Unit 2, the request came well after the project had been fully approved. FOF 400. This type of afterthought analysis (even if it had been finished just before the start of construction instead of just after) does not serve as a reasonable emissions calculation or prevent a finding of liability, particularly where the analysis fails to account for the company's actual expectations of performance improvements, as discussed below.

Ameren's "Amended" Unit 2 analysis is not helpful because it was not performed until even later and was only performed well after the project was completed, after Ameren received the Notice of Violation from EPA, after this lawsuit was filed, and only upon the request of Ameren's in-house counsel. FOF 401, 405-406. Ameren's in-house counsel asked the Environmental Services Department to perform this post-project amended "expectations" analysis to include the results of the amended EDF case that counsel had previously asked Mr. Hutcheson to run. That case was modeled to include additional efficiency improvements that had been left off from the Original run. FOF 401-407. Because the Amended analysis was performed under these circumstances and presumably for the purpose of this litigation, any credibility the analysis might otherwise have is severely diminished. Ameren's expert, Mr.

King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes, agreeing that in using such a run, a source runs the risk of looking like it was "cooking the forecast" to project no emissions increase. FOF 408.

In addition to these procedural flaws, the analyses Ameren actually did conduct suffered from considerable substantive flaws. Ameren's Original analysis failed to fully incorporate the improved availability the company expected after the project. The modeling run used for the projection assumed 95% availability for Unit 2 after the project. FOF 257, 410. But, as discussed in Subsection II.B.2 above, Ameren expected that the best years after the project would be 2–3% higher than that, based on its experience with Unit 1's record availability in 2008. The justification seeking ultimate approval for the project was based on an availability of nearly 97%. The regulations require Ameren to consider the highest year of emissions. 40 C.F.R. § 52.21(b)(41)(i). By limiting availability to 95%, Ameren failed to perform a reasonable analysis under the PSD rules.

Even without fully accounting for the project's effects, Ameren's analysis would have shown an NSR-triggering increase except for what Ameren excluded based on its capable of accommodating analysis. In calculating the capable of accommodating number, however, Ameren posited that the unit could have run all available hours *and* that it could have polluted at its 95^{th} percentile emissions rate. FOF 412. The effect was that the total capable of accommodating number was more SO_2 per year than Ameren had emitted since 1995 (when Acid Rain rules were taking effect). FOF 417. Had Ameren used a more realistic emissions rate, its own analysis would have shown that it was *not* capable of accommodating the projected increase. FOF 413–16, 419, 420.

The post-hoc analysis by Ms. Ringelstetter begins with the same flaw as Mr. Hutcheson's calculation. Ms. Ringelstetter also failed to properly account for the project. She used the same modeling run as Mr. Hutcheson and as a result did not account for Ameren's actual, expected highest year of availability and "business activity." In addition, she attributed the entire capacity gain modeled in that run to the turbine, despite the fact that Ameren expected increased capacity resulting from the boiler work as well, as described in Subsection II.B.2 above. FOF 430.

Finally, Ms. Ringelstetter did not do her own analysis of whether the increased emissions projected by the model were related to the project.[27] FOF 437. She simply assumed they were not. FOF 437–38. Because her assumptions are incorrect, Ms. Ringelstetter's analysis is not persuasive.

EVIDENTIARY ISSUES FROM TRIAL

At trial and in post-trial briefing, both parties moved to exclude, strike, or deem irrelevant certain testimony or exhibits. For the reasons stated below, to the extent I have relied on evidence and testimony challenged by either party in my findings of fact and conclusions of law set out above, the parties' motions are denied. To the extent I have not relied on the challenged evidence and testimony, the parties' motions are denied as moot.

I. AMEREN'S MOTIONS TO STRIKE TESTIMONY AND EVIDENCE

A. Ameren's Motions to Strike Mr. Koppe and Dr. Sahu's Testimony and Evidence Concerning the Causation of Actual Emissions Increases

In two motions filed during trial (Doc. 787 and 793), and in a motion filed along with its post-trial briefs (Doc. 832), Ameren moved to exclude certain testimony of Mr. Koppe and Dr. Sahu, along with related exhibits that were admitted into evidence during trial concerning

[27] Ms. Ringelstetter's analysis of the emissions that unit was capable of accommodating is also flawed, for the reasons described in Subsection III.B of my Conclusions of Law.

causation of the actual emissions increases. Ameren argues the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions.

While Ameren argues that Mr. Koppe and Dr. Sahu's opinions are new, there is no dispute that both Mr. Koppe and Dr. Sahu (1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized. Both Mr. Koppe and Dr. Sahu disclosed in their reports that they analyzed post-project actual data. Likewise, their opinions about how the projects enable increased availability and contribute to increases in emissions were discussed in their reports and at their depositions. Ameren argues that because neither expert's report states their opinions in the precise words that Ameren thinks they should have used, the reports did not give notice that the projects at issue actually caused increases in emissions. But the notice required of expert opinions is not so formulaic. While undisclosed expert opinions are inadmissible, Rule 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report." *Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202-1203 (6th Cir. 2006) (holding the district court erred in excluding the testimony of an expert accounting witness because he failed to recite in his report that his opinion was based on "generally accepted accounting principles," the phrase used in the contract at issue in the case; further holding there was no authority for the "mechanical and formalistic ruling" that an expert's opinion must state such "magic words"); *see also Wood v. Robert Bosch Tool Corp.*, No. 4:13 CV 01888 TCM, 2015 WL 5638040, at *8 (E.D. Mo. 2015) (denying in part a motion to strike new expert opinion statements because the offered statement "clarifies [the expert witness's] earlier information, does not contradict it, and should not be surprising to Defendant or its experts"). For these reasons, and those set out in the United States' post-trial brief (*see*

Doc. 831 at 50-56) and its opposition to Ameren's motion to strike (*see* Doc. 836), Mr. Koppe and Dr. Sahu's challenged opinions are not "new opinions." Ameren had sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions.

Moreover, Ameren cannot show that it was prejudiced by the challenged testimony or the admission of the exhibits. The evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence. Additionally, Ameren had the opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions. *See* Doc. 831 at 50-56. Finally, Mr. Koppe's testimony regarding Ameren's full load tests and related exhibit 928 do not prejudice Ameren. Exhibit 928 is merely a summary exhibit of Ameren's own capability data. Ameren itself argued at summary judgment that such summary evidence containing simple mathematic calculations (averaging pre-project and post-project data and comparing them) is admissible. Moreover, Mr. Koppe considered the full load tests along with numerous other materials to reach his conclusion that the capacity increase was due to the projects, making the exhibit cumulative evidence.

Accordingly, I find that the opinions were sufficiently disclosed and that Ameren has not suffered any prejudice from the admission of that testimony because it had notice and opportunity to test it and because it is in part cumulative evidence. As a result, I will not strike Mr. Koppe and Dr. Sahu's testimony on the causation of the actual emissions, Mr. Koppe's testimony concerning the increased MW capability at Unit 2, or the related challenged exhibits.

B. Ameren's Motion to Strike Dr. Hausman's Testimony Criticizing Ms. Ringelstetter's Opinions

Ameren has also moved to strike certain testimony of Dr. Hausman, arguing that he offered new opinion testimony at trial when he criticized Ms. Ringelstetter's analysis. Ameren asks me to strike Dr. Hausman's testimony from the record per Fed. R. Civ. P. 26. In the challenged testimony, Dr. Hausman testified about the different ProSym runs he and Ms. Ringelstetter analyzed, which included a discussion of why he chose the particular run selected. This testimony is not a new opinion that should be stricken under Rule 26. Rather, as Rule 26 contemplates, Dr. Hausman's testimony merely clarified his previously disclosed opinion, explaining why he chose the ProSym run he used and how the different runs he and Ms. Ringelstetter used factored into the different conclusions each expert drew. *Thompson*, 470 F.3d at 1202-1203. Moreover, Ameren has not shown it was prejudiced by this testimony, as it had always had the opportunity to test the basis of Dr. Hausman's analysis. *See also* Doc. 836 at 17 (discussing the lack of prejudice to Ameren).

As a result, I will not strike Dr. Hausman's testimony concerning the differences between his and Ms. Ringelstetter's analyses because it is not undisclosed testimony and Ameren cannot show it was prejudiced by the testimony.

II. THE UNITED STATES' MOTION TO CURTAIL RE-LITIGATION OF THE LAW OF THE CASE

In its post-trial brief, the United States also raised an evidentiary issue, renewing its motion in limine to curtail Ameren's re-litigation of the law of the case. *See* Doc. 757; Doc. 758 at Section IV.B. The United States argues that three categories of evidence Ameren presented at trial are irrelevant and should be excluded:[28] (1) applicability analyses or permitting documents that were generated after the projects at issue in this case and involving different facilities operating under separate state implementation plans at different types of sources, (2) testimony from EPA or state agency staff regarding the operation and application of regulatory provisions, and (3) PowerPoint presentations and other pamphlets discussing NSR regulations.

Ameren argues that these categories of evidence are relevant, not to establish the reasonableness of any legal interpretation, but to establish the reasonableness of its engineering judgments, emissions analyses, and predictions of the future.

To the extent I rely on the challenged evidence in my findings and conclusions above, I will deny the United States' motion. To the extent I have not relied on the challenged evidence, the motion is denied is moot.

CONCLUSION

For the reasons set out above, I find that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act. The 2007 project at Rush Island Unit 1 and the 2010 project at Rush Island Unit 2 were each major modifications under the PSD provisions of the Clean Air Act. Ameren violated the requirements of the PSD program by failing to obtain a preconstruction permit and install best available pollution control technology, among other requirements. Ameren also violated Title V of the Clean Air Act and its operating permit by performing a major modification without obtaining the required permit and by not including applicable requirements in its operating

[28] The United States seeks to exclude the following exhibits and testimony: Ameren exhibits BQ, PQ, PV, QJ, QS, RB, RC, RD, RE, RG, RH, RN, OY, OZ, PA, PF, and deposition testimony from David Campbell, Trial Tr. Vol. 12, 9:10-11:8; Gregg Worley, Trial Tr. Vol. 12, 4:2-5:22; and James Stewart, Trial Tr. Vol. 12, 11:4-13:2.

permit applications. As a result, I will enter a finding of liability against Ameren. A status conference will be set to address remedies.

Accordingly,

IT IS HEREBY ORDERED that Defendant Ameren Missouri is found liable under the Clean Air Act, 42 U.S.C. § 7401 *et seq*.

IT IS FURTHER ORDERED that a status conference to address remedies is set for **Wednesday, February 15, 2017 at 11:00 a.m.** in courtroom 16-South.

IT IS FURTHER ORDERED that the United States' Motion in Limine to Curtail Ameren's Re-Litigation of the Law of the Case #[757] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that Ameren's Motion to Treat Certain KDHE Produced Documents as Highly Confidential During Trial #[778] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Robert Koppe's New Causation Opinions #[787] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Dr. Ranajit Sahu's New Opinions #[793] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Strike EPA's New Expert Opinion Evidence and Related Trial Exhibits #[832] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that the Parties' Joint Motion to Correct Clerk's Exhibit List #[829] is **GRANTED**.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 23rd day of January, 2017.

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

Deborah S. Hunt
Clerk

100 EAST FIFTH STREET, ROOM 540
POTTER STEWART U.S. COURTHOUSE
CINCINNATI, OHIO 45202-3988

Tel. (513) 564-7000
www.ca6.uscourts.gov

Filed: January 10, 2017

Mr. Thomas A. Benson
U.S. Department of Justice
Environment & Natural Resources Division
P.O. Box 7611
Washington, DC 20044

Mr. Mark B. Bierbower
Mr. F. William Brownell
Mr. Makram Bassam Jaber
Hunton & Williams
2200 Pennsylvania Avenue, N.W.
Washington, DC 20037

Mr. Shannon W. Fisk
Earthjustice, 1617 John F. Kennedy Boulevard, Suite 1675
Philadelphia, PA 19103

Mr. Harry Margerum Johnson III
Mr. George Peter Sibley III
Hunton & Williams
951 E. Byrd Street
Richmond, VA 23219

Mr. Matthew J. Lund
Pepper Hamilton
4000 Town Center, Suite 1800
Southfield, MI 48075

Mr. Brent Rosser
Hunton & Williams
101 S. Tryon Street, Suite 3500
Charlotte, NC 28280

Mr. Michael J. Solo Jr.
DTE Energy, One Energy Plaza, 688 WCB
Detroit, MI 48226

Ms. Mary Melissa Whittle
Earthjustice
3904 Bonnell Drive
Austin, TX 78731

Re: Case Nos. 14-2274/2275, *USA v. DTE Energy Company, et al*
Originating Case No. : 2:10-cv-13101

Dear Counsel,

The court today announced its decision in the above-styled cases.

Enclosed is a copy of the court's opinion together with the judgment which has been entered in conformity with Rule 36, Federal Rules of Appellate Procedure.

Yours very truly,

Deborah S. Hunt, Clerk

Cathryn Lovely
Deputy Clerk

cc: Mr. David J. Weaver

Enclosures

Mandate to issue.

RECOMMENDED FOR FULL-TEXT PUBLICATION
Pursuant to Sixth Circuit I.O.P. 32.1(b)

File Name: 17a0006p.06

UNITED STATES COURT OF APPEALS

FOR THE SIXTH CIRCUIT

UNITED STATES OF AMERICA (14-2274), *Plaintiff-Appellant*, SIERRA CLUB (14-2275), *Intervenor Plaintiff-Appellant*, *v*. DTE ENERGY COMPANY and DETROIT EDISON COMPANY, *Defendants-Appellees*.	Nos. 14-2274/2275

Appeal from the United States District Court
for the Eastern District of Michigan at Detroit.
No. 2:10-cv-13101—Bernard A. Friedman, District Judge.

Argued: December 10, 2015

Decided and Filed: January 10, 2017

Before:BATCHELDER, DAUGHTREY, and ROGERS, Circuit Judges.

COUNSEL

ARGUED: Thomas A. Benson, UNITED STATES DEPARTMENT OF JUSTICE, Washington, D.C., for Federal Appellant. Mary Whittle, EARTHJUSTICE, Philadelphia, Pennsylvania, for Appellant Sierra Club. F. William Brownell, HUNTON & WILLIAMS LLP, Washington, D.C., for Appellees. **ON BRIEF:** Thomas A. Benson, UNITED STATES DEPARTMENT OF JUSTICE, Washington, D.C., for Federal Appellant. Mary Whittle, Shannon Fisk, EARTHJUSTICE, Philadelphia, Pennsylvania, for Appellant Sierra Club. F. William Brownell, Mark B. Bierbower, Makram B. Jaber, HUNTON & WILLIAMS LLP, Washington, D.C., Brent A. Rosser, HUNTON & WILLIAMS LLP, Charlotte, North Carolina, Harry M. Johnson III, George P. Sibley III, HUNTON & WILLIAMS LLP, Richmond, Virginia, Michael J. Solo, DTE ENERGY COMPANY, Detroit, Michigan, for Appellees.

DAUGHTREY, J., delivered the opinion in which BATCHELDER, J., joined in the result. BATCHELDER, J. (pp. 9–14), delivered a separate opinion concurring in the judgment. ROGERS, J. (pp. 15–29), delivered a separate dissenting opinion.

OPINION

MARTHA CRAIG DAUGHTREY, Circuit Judge. This case is before us for a second time, following an order of remand in *United States v. DTE Energy Co.* (*DTE I*), 711 F.3d 643 (6th Cir. 2013). As we noted there, regulations under the Clean Air Act require a utility seeking to modify a source of air pollutants to "make a preconstruction projection of whether and to what extent emissions from the source will increase following construction." *Id.* at 644. This projection then "determines whether the project constitutes a 'major modification' and thus requires a permit" prior to construction, as part of the Act's New Source Review (NSR) program. *Id.*; *see also* 42 U.S.C. §§ 7475, 7503; 40 C.F.R. § 52.21. The NSR regulations require an operator to "consider all relevant information" when estimating its post-project actual emissions but allow for the exclusion of any emissions "that an existing unit could have accommodated during the [baseline period] . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(a) and (c). An operator must document and explain its decision to exclude emissions from its projection as resulting from future "demand growth" and provide such information to the EPA or to the designated state regulatory agency. 40 C.F.R. § 52.21(r)(6)(i)–(ii).

Defendants DTE Energy Co. and its subsidiary, Detroit Edison Co. (collectively DTE), own and operate the largest coal-fired power plant in Michigan at their facility in Monroe, where, in 2010, DTE undertook a three-month-long overhaul of Unit 2 costing $65 million. On the day before it began construction, DTE submitted a notification to the Michigan Department of Environmental Quality stating that DTE predicted an increase in post-construction emissions 100 times greater than the minimum necessary to constitute a "major modification" and require a preconstruction permit. DTE initially characterized the projects as routine maintenance, repair, and replacement activities, a designation that, if accurate, would exempt the projects from triggering NSR.[1] *See New York v. U.S. Envtl. Prot. Agency*, 443 F.3d 880, 883–84 (D.C. Cir. 2006). DTE also informed the state agency that it had excluded the entire predicted emissions increase from its projections of Unit 2's post-construction emissions based on "demand growth." This designation, if it could be established to the agency's satisfaction, also would have exempted DTE's modification from the necessity of a permit and, thus, allowed DTE to postpone some of the pollution-control installations that were planned as a future upgrade.[2] *See* 40 C.F.R. § 52.21(b)(41)(ii)(c). DTE began construction on Monroe Unit 2 without obtaining an NSR permit.

After investigation of DTE's projections, the EPA filed this enforcement action, challenging the company's routine-maintenance designation and its exclusion for "demand growth," and insisting that DTE should have secured a preconstruction permit and included pollution controls in the Unit 2 overhaul to remediate the projected emissions increases. The district court granted summary judgment to DTE, holding that the EPA's enforcement action was premature because the construction had not yet produced an actual increase in emissions. On appeal, we reversed and remanded, holding that the EPA was authorized to bring an enforcement action based on projected increases in emissions without first demonstrating that emissions actually had increased after the project. *DTE I*, 711 F.3d at 649.

On remand, the district court again entered summary judgment for DTE, this time focusing on language in our first opinion to the effect that "the regulations allow operators to undertake projects without having EPA second-guess their projections." *Id.* at 644. The district court apparently (and mistakenly) took this to mean that the EPA had to accept DTE's projections at face value, holding that:

> EPA is only entitled to conduct a *surface review* of a source operator's preconstruction projections to determine whether they comport with the letter of the law. Anything beyond this *cursory examination* would allow EPA to "second-

---

[1]As it turns out, the EPA does not consider a $65-million overhaul to be routine by definition.

[2]Those upgrades have since been completed. Since the Monroe Unit 2 overhaul was completed in 2010, DTE has installed the scrubbers and other pollution controls necessary to remediate toxic emissions at the facility, so that implementation is no longer at issue. Appellee's Br. at 13 n.4. But, if it is found to have violated the Act, DTE still could face monetary penalties and be required to mitigate excess emissions caused by the delay in installing pollution controls.

> guess" a source operator's calculations; an avenue which the Sixth Circuit explicitly foreclosed to regulators. [Emphasis added.]
>
> In this case, EPA claims that defendants improperly applied the demand growth exclusion when they "expected pollution from . . . Unit 2 to go up by thousands of tons each year after the overhaul," and then discounted this entire emissions increase by attributing it to additional consumer demand. In other words, EPA does not contend that defendants violated any of the agency's regulations when they computed the preconstruction emission projections from Unit 2. Rather, EPA takes defendants to task over *the extent* to which they relied upon the demand growth exclusion to justify their projections. This is exactly what the Sixth Circuit envisioned when it precluded EPA from second-guessing "the making of [preconstruction emission] projections." [Internal citations omitted.]

The problem with the district court's analysis is two-fold. First, the focus on so-called "second-guessing" is misplaced. That language from our earlier opinion is, technically speaking, *dictum*, because the holding of the opinion was, as noted above, that the EPA could bring a preconstruction enforcement action to challenge DTE's emissions projections. Second, in reviewing an operator's attribution of increased emissions to demand growth, the EPA definitely is not confined to a "surface review" or "cursory examination."

Indeed, two agency pronouncements, dating back to 1992, make clear that the EPA must engage in actual review. The first is in 57 Fed. Reg. 32,314, 32,327 (July 21, 1992), which is quoted in our first opinion: "[W]hether the [demand growth] exclusion applies 'is a *fact-dependent* determination that must be *resolved on a case-by-case basis*.'" *DTE I*, 711 F.3d at 646 (emphasis added). The second is found in 72 Fed. Reg. 72,607, 72,611 (Dec. 21, 2007) (emphasis added): NSR record-keeping requirements "establish[] an adequate paper trail to allow enforcement authorities to *evaluate* [an operator's] claims concerning what amount of an emissions increase is related to the project and *what amount is attributable to demand growth*."

But the EPA cannot *evaluate* a *fact-dependent* claim on a *case-by-case* basis unless the operator supplies supporting facts, which the record establishes was not done here. In other words, a valid projection must consist of more than the following list, which is, in effect, all that DTE provided to the EPA:

Increase in nitrous oxide emissions…………………….. ....……………	4,096 tons
Increase in sulfur dioxide emissions……………….............……………	3,701 tons
Total increase in emissions……………………….........……………...	7,797 tons
Less amount attributable to demand growth………………....…...………...	7,797 tons
NSR projection for post-construction emissions…………....…………………..	0 tons

The record before us is devoid of any support for this thoroughly superficial calculation.[3] DTE baldly asserted that it was excluding from its projections "'that portion of the unit's emissions following the project that an existing unit could have accommodated . . . and that are also unrelated to the particular project,' including increases due to demand and market conditions or fuel quality." Mar. 12, 2010 Notice Letter, Page ID 165 (quoting the Michigan equivalent of 40 C.F.R. § 52.21(b)(41)(ii)(c)). DTE then went on to claim that "emissions and operations fluctuate year-to-year due to market conditions," and "[a]t some point in the future, baseline levels may be exceeded again, but not as a result of this outage." *Id.* This letter provided no rationale for the company's claim that Unit 2 was capable of accommodating the increased emissions prior to the construction projects or that future growth in the demand for electricity was the sole cause of the projected increase in pollutants. Although DTE later sent two more letters to the EPA supposedly clarifying the method of calculating baseline emissions, these letters also failed to explain why DTE applied the demand-growth exclusion to its entire projected-emissions increase. In its motion for summary judgment below, DTE claimed that it attributed the increased emissions to future demand for power "[b]ased on the company's business and engineering judgment" (Page ID 6716), but gave no specific information to support that judgment.

In fact, not one of DTE's attempts to justify its application of the demand-growth exclusion was supported by documentation, without which the EPA could not meaningfully evaluate DTE's projections. There was, in truth, nothing to evaluate. Moreover, the results of a

[3]Clearly, DTE failed to comply with the regulation requiring it to "document . . . the amount of emissions excluded under paragraph (b)(41)(ii)(c) of this section and an explanation for why such amount was excluded." 40 C.F.R. § 52.21(r)(6)(i).

computer model that DTE ran, when it was rerun by the EPA, showed that DTE should actually have predicted a *decrease* in demand. (Page ID 372) Contrary to DTE's "business and engineering judgment," what did occur in the immediate post-construction period was a decline in consumer demand, not an increase. Appellee's Br. at 64.

DTE's failure to carry its burden to set out a factual basis for its demand-growth exclusion is just one problem with its projections. In order to exclude increased emissions as the product of increased demand under 40 C.F.R. § 52.21(b)(41)(ii), the company must establish (1) that the projected post-construction emissions could have been accommodated during the preconstruction period *and* (2) that the projected emissions are unrelated to the construction project.[4] As to the first requirement, DTE did not and could not establish that the increase in emissions could have been accommodated during the baseline period. Prior to the overhaul, DTE was running Unit 2 at full capacity—that is, Unit 2 was operating every hour that it could be operated. (Page ID 294) But Unit 2 was experiencing continual outages that kept it from running almost 20 percent of the time (Page ID 302), which is obviously why DTE shut it down for three months to accomplish the overhaul, aimed at increasing efficiency and reliability. For the same reason, DTE did not and could not establish that the increase in emissions was unrelated to the construction process. The planned increase in efficiency and reliability would allow the plant to operate for at least an additional 12 days each year (Page ID 306), which in turn would result in increased emissions unless the construction also had included pollution controls, as the issuance of a permit would have required.

In *DTE I*, we referenced the second sentence of 40 C.F.R. § 52.21(r)(6)(ii):

> If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i). *Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction.*

[4]Both requirements must be met. *See New York v. U.S. Envtl. Prot. Agency*, 413 F.3d 3, 33 (D.C. Cir. 2005) (citing 67 Fed. Reg. 80,186, 80,203 (Dec. 31, 2002)) ("[E]ven if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but it can be shown that the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the modification project, and cannot be subtracted from the projection of post-change actual emissions.").

711 F.3d at 650 (emphasis added). Judge Rogers's current dissent seems to take a broader view of this regulation than the text permits in repeatedly cautioning that permitting the EPA's enforcement action to go forward would create "a de facto prior approval system." (Rogers Opinion at 15, 17, 19) But this reading is patently too expansive, because the regulation does not say that the EPA has to accept projections at face value or that it is prohibited from questioning their legitimacy. Instead, and in context, the rule means that once the required information has been submitted to the EPA for review, the operator does not have to delay construction until it receives a decision on the necessity of a permit, but may commence construction prior to a "determination from the Administrator." Of course, if the operator actually begins construction without waiting for a "determination" from the EPA and it later turns out that a permit was required, a violation of NSR has occurred, and the operator risks penalties and injunctive relief requiring mitigation of illegal emissions, a possible shut down of the unit, or a retrofit with pollution controls to meet emissions standards. *See, e.g.*, *United States v. Cinergy Corp.*, 618 F. Supp. 2d 942, 971 (S.D. Ind. 2009), *rev'd on other grounds*, 623 F.3d 455 (7th Cir. 2010).

In short, DTE was not required by the regulations to secure the EPA's approval of the projections, or the project, before beginning construction, but in going forward without a permit, DTE proceeded at its own risk. The EPA is not prevented by law or by our prior opinion in *DTE I* from challenging DTE's preconstruction projections, such as they are. Viewing the facts in the light most favorable to the EPA, we conclude that there are genuine disputes of material fact that preclude summary judgment for DTE regarding DTE's compliance with NSR's statutory preconstruction requirements and with agency regulations implementing those provisions. Therefore, we REVERSE the district court's grant of summary judgment to DTE and REMAND this case for further proceedings consistent with this opinion.

In terms of the remand, it is important to note that the panel unanimously agrees—now that *DTE I* is the law of this case and of the circuit—that actual post-construction emissions have no bearing on the question of whether DTE's preconstruction projections complied with the regulations. (Batchelder Concurrence at 6, 7; Rogers Opinion at 20) *DTE I* foreclosed that question in holding that an operator who begins construction without making a projection in accordance with the regulations is subject to enforcement, no matter what post-construction data later shows. 711 F.3d at 649. The district court erred initially and again on remand when it ruled that post-construction data could be used to show that a construction project was not a "major modification." Apparently, it is necessary to reiterate that the applicability of NSR must be determined *before construction commences* and that liability can attach if an operator proceeds to construction without complying with the preconstruction requirements in the regulations. Post-construction emissions data cannot prevent the EPA from challenging DTE's failure to comply with NSR's preconstruction requirements.

CONCURRENCE IN THE JUDGMENT

ALICE M. BATCHELDER, Circuit Judge, concurring in the judgment only. When this appeal was here before, the majority vacated a grant of summary judgment and remanded for the USEPA to challenge DTE's pre-construction emission projections. I dissented because actual events had disproven USEPA's projected (hypothetical) emissions calculations (which were the entire basis for its claim), USEPA had not accused DTE of any noncompliance with any regulations, and the majority opinion was creating a de facto prior-approval or second-guessing scheme. *See United States v DTE Energy Co.* (*DTE I*), 711 F.3d 643, 652-54 (6th Cir. 2013) (Batchelder, J., dissenting). On remand, however, the district court again granted summary judgment to DTE, finding that USEPA had not raised a valid claim of regulatory non-compliance and reasserting that actual events had disproven USEPA's hypothetical emission projections. USEPA appealed again, relying on the prior decision by the *DTE I* majority.

Therefore, this time around we again face the question of whether USEPA may second guess DTE's preconstruction emission projections, using its own hypothetical projections, without regard to actual events. The dissent here would affirm this grant of summary judgment on the basis that USEPA has not raised a valid claim of regulatory non-compliance and mere second guessing is impermissible. That was my view during the prior *DTE I* appeal, as explained fully in that dissent, and I would very much like to agree. But, unlike the prior appeal, this appeal does not present an open issue and I cannot ignore the *DTE I* opinion or pretend that it means something other than what it says. Despite my continuing disagreement with it, *DTE I* is the law of the Sixth Circuit. Consequently, USEPA was entitled to rely on it and the district court was obliged to follow it. More importantly, we must follow it as well.

Simply put, the *DTE I* opinion clearly requires that we reverse the district court's grant of summary judgment to DTE and remand for reconsideration consistent with that prior opinion. Therefore, I concur in the judgment to REVERSE and REMAND, but I do not join any language or analysis in the lead opinion that could be read to expand the prior *DTE I* opinion.

I.

DTE Energy planned renovations at its Monroe Power Plant. In accordance with all applicable state and federal regulations, it conducted its own determination as to whether the renovations would constitute a "significant modification" that would require a PSD permit, and determined that it would not. Specifically, DTE relied on "demand growth" to predict that its post-project emissions would not increase from its baseline emissions levels and that there was no "reasonable possibility" that this renovation would be a significant modification.

But months later (after construction was well underway), USEPA sued DTE, claiming that—based on USEPA's expert's different hypothetical emission predictions—DTE should have gotten a PSD permit. DTE moved for summary judgment, arguing that a PSD permit was unnecessary based on either its pre-construction prediction or actual post-construction test results, which established that emissions did not increase (and actually decreased) after the renovation. Basically, USEPA wanted DTE to go back in time and re-do its predictions the same way USEPA's expert would have done them, so as to predict emissions increases and mandate a PSD permit, even though actual events had already proven USEPA's predictions were wrong.

The pertinent regulations say: "a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase . . . and a significant net emissions increase. . . . The project is not a major modification if it does not cause a significant emissions increase. . . . Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase." 40 C.F.R. § 52.21(a)(2)(iv).[1] I read this last sentence also to mean that,

[1] In their entirety:

(a) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, *a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase* (as defined in paragraph (b)(40) of this section), *and a significant net emissions increase* (as defined in paragraphs (b)(3) and (b)(23) of this section). *The project is not a major modification if it does not cause a significant emissions increase.* If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(b) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(c) through (f) of this section.

regardless of any pre-construction projections, a major modification *does not result* if the project *does not cause* an actual significant emissions increase or significant net emissions increase. But the *DTE I* panel majority did not read it this way, nor did USEPA. According to them, this regulation means that a renovation is a major modification (requiring a PSD permit) if either a USEPA-approved calculation predicts an emissions increase or emissions actually increase. And, despite the fact that the rules delegate calculation of the prediction to the operator (here DTE), and contain no requirement that the operator obtain USEPA review or approval, USEPA deems both the operator's prediction and reality meaningless if USEPA disagrees.

Leading in to *DTE I*, the district court had rejected USEPA's view and granted summary judgment to DTE in a thorough, well-written, and (I thought) correct opinion, explaining that DTE had followed the regulations and predicted no "significant modification," thus excusing it from the permit requirements. Moreover, actual events had proven DTE's prediction correct (and USEPA's incorrect). But, on appeal, the *DTE I* majority reversed, opining that: "[a] preconstruction projection is subject to an enforcement action by EPA to ensure that the projection [wa]s made pursuant to the requirements of the regulations." *DTE I*, 711 F.3d at 652.

I dissented on three bases. First, the subsequent actual emissions data, which showed an actual emissions *decrease*, "render[ed] moot the case or controversy about *pre*-construction emissions projections—there can be no permitting or reporting violation because there was, conclusively, no major modification." *Id.* (Batchelder, J., dissenting). Next, I explained that, regardless of any purported disclaimer that this was not a prior approval scheme, the reality is that "if the USEPA can challenge the operator's scientific preconstruction emissions projections in court—to obtain a preliminary injunction pending a court decision as to whether the operator or USEPA has calculated the projections correctly—that is the exact same thing as requiring prior approval." *Id.* at 653 (Batchelder, J., dissenting) (footnote omitted). Finally, I explained (twice) that USEPA was *not* claiming that DTE had failed to follow the regulations:

> The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition in paragraph (b)(3) of this section. *Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.*

40 C.F.R. § 52.21(a)(2)(iv) (emphasis added).

> To be sure, neither of these issues is in question here: there is no contention that DTE failed to prepare a projection (it did) or that DTE misread the rules in applying the governing regulation (it did not). Instead, USEPA relies on its expert's opinion to second-guess DTE's projections. *See* Appellant Br. at 25 ("EPA can use its projections to demonstrate that the operator should have projected a PSD-triggering emissions increase."); 24 ("The agency can use its own emissions projections to demonstrate that a proper pre-construction analysis would have shown an emissions increase."). USEPA's disagreement is entirely technical and scientific; the dispute is not about the regulation.

Id. at 652 n.1 (Batchelder, J., dissenting).

> It bears repeating that USEPA does not contend that DTE failed to make a projection or failed to follow the regulations; rather, USEPA relies on its expert's opinion to second-guess DTE's technical/scientific projections. *See* n.1, *supra.* If the issue here had been one of the foregoing (i.e., if USEPA had wanted to challenge an operator's failure to make a projection or failure to follow the governing regulation—a challenge that would not require USEPA to rely on an expert's scientific opinion), that would present different considerations and perhaps result in a different outcome. Because neither of those issues is before us, it is neither necessary nor appropriate to address them here.

Id. at 652 n.2 (Batchelder, J., dissenting). If the *DTE I* holding had been that USEPA was limited to challenging only whether DTE had failed to follow the regulation, the *DTE I* majority would have had no basis for reversal, inasmuch as USEPA had not raised any such challenge. Instead, *DTE I*'s inescapable actual holding was that USEPA may use its own expert's pre-construction predictions to force DTE to get a PSD construction permit (or to punish DTE for failing to get a PSD permit), even if USEPA's disagreement is based on debatable scientific or technical reasons and even if actual events have proven USEPA's expert's prediction wrong.

On remand, however, the district court tried to limit the *DTE I* holding rather than just doing as instructed, and once again granted summary judgment to DTE, saying:

> In this case, EPA claims that defendants improperly applied the demand growth exclusion when they expected pollution from Unit 2 to go up by thousands of tons each year after the overhaul and then discounted this entire emissions increase by attributing it to additional consumer demand. In other words, EPA does not contend that defendants violated any of the agency's regulations when they computed the preconstruction emission projections from Unit 2. Rather, EPA takes defendants to task over *the extent* to which they relied upon the demand growth exclusion to justify their projections. This is exactly what the

> Sixth Circuit envisioned when it precluded EPA from second-guessing the making of preconstruction emission projections. Moreover, EPA does not point to any regulation requiring source operators to demonstrate the propriety of their demand growth exclusion calculations. And without adequate proof that defendants violated the regulations governing preconstruction emission projections, the instant action cannot withstand summary judgment.
>
> Even assuming that EPA's reviewing authority is as broad as the agency claims, the Court is bewildered by the prospect of what, if anything, the agency stands to gain by pursuing this litigation. Insofar as the government asserts that defendants misapplied the demand growth exclusion, this contention is belied by the fact that defendants have demonstrated, and the government concedes, that the actual post-project emissions from Unit 2 never increased. Therefore, since its own preconstruction emission projections are now verifiably inaccurate, the government is unable to show that the renovations to Unit 2 constituted a major modification.

R. 196 at 3-4; PgID 7515-16 (quotation marks, editorial marks, and citations omitted).

This analysis ignores two major holdings from *DTE I*. First, DTE had already established in *DTE I* that the actual post-project emissions had decreased, so even knowing that USEPA's pre-construction projections were "verifiably inaccurate," *DTE I* still remanded for a ruling on the *pre*-construction projections, rendering the actual emissions legally irrelevant. Second, we were also fully aware in *DTE I* that USEPA was not claiming that DTE had overlooked, misapplied, or violated any regulations; USEPA's only claim was that DTE had scientifically miscalculated the predicted emissions. If the question had been whether or not USEPA could challenge DTE's failure to comply with the regulations, then *DTE I* would have affirmed the summary judgment because USEPA had raised no such claim. And I would have had no need to dissent.[2] Rather, the *DTE I* majority remanded for a ruling on USEPA's claim that DTE had technically or scientifically miscalculated the hypothetical pre-construction emissions.

[2]As I said in that dissent: "It bears repeating that USEPA does not contend that DTE failed to make a projection or failed to follow the regulations. . . . [I]f USEPA had wanted to challenge an operator's failure to make a projection or failure to follow the governing regulation. . . , that would present different considerations and perhaps result in a different outcome." *DTE I*, 711 F.3d at 652 n.2 (Batchelder, J., dissenting).

II.

Now, USEPA appeals the grant of summary judgment and argues that the district court did not follow the *DTE I* majority's remand instructions.

A.

On remand, USEPA re-framed its claims against DTE as noncompliance with particular regulations in an admitted effort to satisfy the *DTE I* majority's purported limiting language. That is, USEPA now argues that DTE violated the regulations "in two critical ways." Apt. Br. at 51. First, USEPA claims that DTE failed to base its predictions on "all relevant information," required by 40 C.F.R. § 52.21(b)(41)(ii)(a), and ignored its own modeling when claiming that any increase was due to demand increases, in violation of 40 C.F.R. § 52.21(b)(41)(ii)(a). Second, USEPA claims that, in applying the demand growth exclusion, DTE excluded emissions that USEPA believed were related to the project, contrary to § 52.21(b)(41)(ii)(c).

According to the *DTE I* opinion, this is a legitimate challenge. In fact, this is a far more legitimate challenge than that which the majority opinion condoned in the *DTE I* appeal. Given the *DTE I* holding, the district court erred by rejecting this challenge.

B.

USEPA also argues that "[w]here a source should have expected a project to increase emissions, the work is a major modification and must meet the modification requirements" regardless of "post-project data." Apt. Br. at 54. USEPA relies on the fact that the *DTE I* panel "knew that post-project data showed an emissions decrease, and yet … remanded for further proceedings" anyway; if post-project data were determinative, "there would have been no reason for that remand." Apt. Rep. Br. at 9-10. This reasoning actually applies throughout.

III.

Based on the foregoing, I conclude that, because we are bound by the *DTE I* opinion, we must reverse the grant of summary judgment to DTE and remand for reconsideration consistent with that prior opinion. Therefore, I concur in the judgment to REVERSE and REMAND. I do not join any language or analysis that expands or alters the prior opinion.

DISSENT

ROGERS, Circuit Judge, dissenting. The Clean Air Act requires an operator of a major source of air pollution to obtain a permit before beginning construction on a project that the operator predicts will significantly increase pollution at the operator's source. In 2010, EPA brought an enforcement action against DTE Energy Company and Detroit Edison Company, alleging that the defendants had violated the Clean Air Act by failing to obtain permits before beginning construction on projects at their power plant in Monroe, Michigan. DTE contended that EPA's enforcement action was premature because DTE's projects had not yet caused pollution to increase, and the district court agreed. On appeal, this court reversed the district court's grant of summary judgment to DTE, holding that EPA could bring an enforcement action to ensure that an operator performed a pre-construction projection about whether its proposed project would cause pollution to increase, but that full review of the validity of the projection at the pre-construction stage was not consistent with the statute and regulatory scheme. On remand, the district court granted DTE's renewed motion for summary judgment, reasoning that DTE met the basic requirements, and also because in any event post-construction emissions had not increased. EPA appeals.

Because the undisputed facts establish that DTE complied with the basic requirements of the regulations for making projections, the district court properly granted summary judgment to DTE.

I.

A.

This court's prior opinion explains the regulatory framework that governs this case:

> The 1977 Amendments to the Clean Air Act created a program titled New Source Review. New Source Review forbids the construction of new sources of air pollution without a permit. 42 U.S.C. § 7475. In order to achieve the act's goals of "a proper balance between environmental controls and economic growth," sources already in existence when the program was implemented do not have to

> obtain a permit unless and until they are modified. *New York v. EPA*, 413 F.3d 3, 13 (D.C. Cir. 2005) (quoting 123 Cong. Rec. 27,076 (1977) (statement of Rep. Waxman)). Congress defined a modification as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4). EPA requires owners or operators of [major stationary] sources to obtain permits if they plan a "major modification." [40 C.F.R. § 52.21(a)(2)(iii).] A [major stationary] source is anything that has the potential to emit large quantities of a regulated pollutant. [40 C.F.R § 52.21(b)(1)(i)(a).] A major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated [New Source Review] pollutant . . . and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 52.21(b)(2)(i).

United States v. DTE Energy Co., 711 F.3d 643, 644–45 (2013) (footnotes omitted).

The 2002 New Source Review rules,[1] as adopted by EPA in 2002, provide that for projects that only involve existing emissions units, a "significant emission increase of a regulated [New Source Review] pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . for each existing emissions unit, equals or exceeds the significant amount for that pollutant." 40 C.F.R. § 52.21(a)(2)(iv)(c). To determine whether a project would cause a significant emissions increase, and thus require a permit, an operator must therefore follow three basic steps.

First, the operator must determine the "baseline actual emissions."

Second, the operator must determine the "projected actual emissions." The "projected actual emissions" can be calculated by determining "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated [New Source Review] pollutant in any one of the 5 years (12–month period) following the date the unit resumes regular operation after the project." 40 C.F.R. § 52.21(b)(41)(i). To calculate this amount, the operator must "consider all relevant information, including but not limited to . . . the company's own representations, the company's expected business activity . . . [and] the company's filings with

---

[1]New Source Review actually consists of two programs: "New Source Review for areas classified as 'nonattainment' for certain pollutants and Prevention of Significant Deterioration for areas classified as 'attainment.' Monroe, Michigan actually falls into both categories depending on the pollutant. The two programs are generally parallel and their differences do not affect this case." *DTE Energy*, 711 F.3d at 644 n.1.

the State or Federal regulatory authorities." 40 C.F.R. § 52.21(b)(41)(ii)(a). Further, the operator "[s]hall exclude" from the projected actual emissions "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(c). "Since the most common independent factor is growth in demand for electricity, the exclusion [of this portion of the unit's emissions] is called the 'demand growth exclusion.'" *DTE Energy Co.*, 711 F.3d at 646.

Third, the operator must subtract the baseline actual emissions from the projected actual emissions to determine if the difference between these numbers is "significant." 40 C.F.R. § 52.21(a)(2)(iv)(c). A table in the regulations defines the numeric thresholds that are considered "significant" for each regulated pollutant. 40 C.F.R. § 52.21(b)(23)(i). If the table defines the difference in the projected actual emissions and the baseline actual emissions to be significant, then the operator must obtain a permit before beginning construction on the project. 40 C.F.R. § 52.21(a)(2)(iii). "[A] permit would require the facility to use 'best available control technology' for each regulated pollutant. For grandfathered sources, installing this technology generally leads to a drastic decrease in emissions, even when compared to the preconstruction baseline, at great expense for the operator." *DTE Energy Co.*, 711 F.3d at 645 (citing 42 U.S.C. § 7475(a)(4)).

B.

Detroit Edison Company, a wholly-owned subsidiary of DTE Energy Company, owns and operates the Monroe Power Plant in Monroe, Michigan. In March 2010, DTE began construction projects at Monroe Unit #2, a coal-fired generating unit at the Monroe Power Plant. The projects included the replacement of several components of the unit's boiler tube, including the unit's economizer, pendant reheater, and a portion of the waterwall.

On March 12, 2010, before beginning these projects, DTE submitted calculations about the projects' expected impact on emissions to its reviewing authority, the Michigan Department of Environmental Quality. To make these calculations, DTE used projections that it had previously provided to the Michigan Public Service Commission. DTE created these projections using a "complex 'production cost model' called PROMOD." PROMOD relies on "a number of company-defined inputs"—such as projected market prices for coal and natural gas and expected outage rates—to predict how much Monroe Unit #2 would be used in the future. DTE projected that in the five years after the projects, Monroe Unit #2 would have its maximum emissions of nitrogen oxide and sulfur dioxide in 2013, with emissions increases of 4,096 tons of nitrogen oxide and 3,701 tons of sulfur dioxide at this time. Both of these amounts are more than 40 tons per year increases of either sulfur dioxide or nitrogen oxide, increases which the regulations deem to be significant. 40 C.F.R. § 52.21(b)(23)(i).

However, DTE concluded that the projects would not result in an emissions increase. To reach this conclusion, DTE excluded all of its projected emissions increases from its "projected actual emissions" under the demand growth exclusion. DTE Vice President of Environmental Management and Resources Skiles W. Boyd stated that DTE determined that its projected increase in emissions was "attributable to demand growth" based on its "prediction that there would be substantial demand for electricity generated at DTE's coal-fired power plants in 2013 due to the predicted price of coal versus the price of natural gas and other factors." Boyd also stated that DTE concluded that it could have accommodated these emissions during the baseline period because Monroe Unit #2 "had greater availability during the baseline period than the highest expected utilization of the unit after the project."

On May 28, 2010, EPA sent DTE a letter asserting that its projects constituted a "major modification" and ordering DTE to produce "[a]ny additional information" that supported its contention that the projects did not require a permit. DTE responded on June 1, 2010, stating that its projected increases were "completely unrelated to the project." DTE explained that at the time that it made its projections "a primary driver for a projected increase in generation (and commensurate projected increase in emissions) from the Monroe Power Plant was an expected increase in power demand accompanied by an increase in energy cost." DTE stated that this "increase in power demand" led to "other factors" that influenced emissions. These factors included the fact that Monroe Unit #2 had no periodic outage scheduled in 2013, the year in which DTE projected that the unit would have its maximum emissions, while it had outages planned in 2010, 2012 and 2014. DTE explained that Monroe Unit #2 had no planned outage in 2013 in part because an outage was planned for Monroe Unit #1 in this year and "Monroe Unit 2 must help make up the difference in electricity demand." DTE also explained that it had determined that Monroe Unit #2 "could have generated" the projected increases in emission during the baseline period "had the market required the electricity during our baseline period."

The projects concluded on June 20, 2010. Since the projects were completed, emissions at Monroe Unit #2 have not exceeded pre-project emissions on an annualized basis, and actual emissions were less than baseline emissions in 2011 and 2012.

In June 2010, EPA issued DTE a notice of violation stating that the projects "resulted in a significant net emissions increase" and therefore constituted a "major modification" for which DTE was required to obtain a permit. In August 2010, the United States, acting at the request of EPA, filed a complaint against DTE in federal district court alleging that DTE had violated the Clean Air Act by proceeding to construction on a major modification without obtaining New Source Review permits. Soon after this, the district court ordered DTE not to use Monroe Unit #2 "to any extent that is greater than it was utilized" prior to the completion of the projects and granted Sierra Club's motion to intervene as plaintiffs. The district court subsequently granted DTE's motion for summary judgment, concluding that a determination of whether the projects at issue constituted a major modification was premature because EPA "may pursue [New Source Review] enforcement if and when post-construction monitoring shows a need to do so." The district court also rejected EPA's challenges to the procedural sufficiency of DTE's notice letter to the Michigan Department of Environmental Quality, holding that DTE complied with the Michigan state-law equivalent to the New Source Review reporting requirements.

On appeal, this court reversed, holding that while the "district court's premises are largely correct, they do not support its sweeping conclusion" that "preconstruction New Source Review enforcement is flatly unavailable if reporting requirements are met." 711 F.3d at 649.[2] This court explained that the current New Source Review regulations "take a middle road" between requiring "operators to defend every projection to the agency's satisfaction" and barring

[2]EPA did not appeal the district court's decision that DTE's notice complied with the reporting requirements. *DTE Energy*, 711 F.3d at 649.

EPA from "challenging preconstruction projections that fail to follow regulations" by "trusting operators to make projections but giving them specific instructions to follow." *Id.* This court explained:

> The primary purpose of the projection is to determine the permitting, monitoring, and reporting requirements, so as to facilitate the agency's ability to ensure that emissions do not increase. If there is no projection, or the projection is made in contravention of the regulations guiding how the projection is to be made, then the system is not working. But if the agency can second-guess the making of the projections, then a project-and-report scheme would be transformed into a prior approval scheme. Contrary to the apparent arguments of the parties, neither of these is the case. Instead, at a basic level the operator has to make a projection in compliance with how the projections are to be made. But this does not mean that the agency gets in effect to require prior approval of the projections.

Id.

This court reasoned that the Clean Air Act provides EPA with the ability to "take such measures . . . [that are] necessary to prevent the construction or modification of a major emitting facility which does not conform to the requirements of [the Clean Air Act]." *Id.* at 650 (citing 42 U.S.C. § 7477). Because these requirements "include making projections," in accordance with the rules set forth in the regulations, this court concluded that "EPA's enforcement powers must also extend to ensuring that operators follow the requirements in making those projections." *Id.* EPA could, for instance, bring an enforcement action against an operator who commences construction on a project without making any preconstruction projection. *Id.* EPA could also prevent construction if an operator "uses an improper baseline period or uses the wrong number to determine whether a projected emissions increase is significant." *Id.* This court therefore held that a "preconstruction projection is subject to an enforcement action by EPA to ensure that the projection is made pursuant to the requirements of the regulations" and remanded the case to the district court. *Id.* at 652.

On remand, DTE again moved for summary judgment, arguing that the undisputed facts established that it had complied with the regulations' objective requirements for making preconstruction projections. The district court granted DTE's motion, concluding that this court's decision allows EPA to conduct only "a surface review of a source operator's preconstruction projection to determine whether they comport with the letter of law." *United*

States v. DTE Energy Co., No. 10-cv-13101, 2014 WL 12601008, at *1 (E.D. Mich. Mar. 3, 2014). The district court explained that anything "beyond this cursory examination would allow the EPA" to engage in impermissible "second-guessing" of an operator's calculations. *Id.* The district court determined that EPA had not contended that DTE violated any of the agency's regulations when DTE made its projection but rather impermissibly challenged "*the extent* to which [DTE] relied upon the demand growth exclusion." *Id.* Accordingly, the district court held that EPA's enforcement action failed as a matter of law because there was not "adequate proof that [DTE] violated the regulations governing preconstruction emission projections." *Id.*

Alternatively, the district court held that even if EPA had unfettered authority to challenge the methodology and factual assumptions that DTE used to predict post-project emissions, the district court was "bewildered" by what EPA stood to gain by pursuing the litigation because "the actual post-project emissions from [Monroe] Unit 2 never increased." *Id.*, at *2. The district court explained that the actual post-project emissions established that EPA's "own preconstruction emission projections" were inaccurate and that EPA therefore could not show that DTE's projects constituted a major modification. *Id.*

II.

This court reviews the district court's partial grant of summary judgment to DTE *de novo*. *Therma-Scan, Inc. v. Thermoscan, Inc.*, 295 F.3d 623, 629 (6th Cir. 2002).[3] Summary judgment was proper because the undisputed facts establish that DTE complied with the basic requirements for making projections. *DTE Energy*, 711 F.3d at 649–50. EPA contends that it

[3]Even though some of EPA and Sierra Club's claims against DTE have not been dismissed, this court has jurisdiction to review the district court's partial grant of summary judgment to DTE based on the district court's Rule 54(b) certification. A "district court may certify a partial grant of summary judgment for immediate appeal" under Federal Rule of Civil Procedure 54(b) "if the court expressly determines that there is no just reason for delay." *Planned Parenthood Southwest Ohio Region v. DeWine*, 696 F.3d 490, 500 (6th Cir. 2012). In certifying such a judgment, the district court must (1) "expressly direct the entry of final judgment as to one or more but fewer than all claims or parties in a case" and (2) "expressly determine that there is no just reason to delay appellate review." *Id.* (quoting *Gen. Acquisition, Inc. v. GenCorp., Inc.*, 23 F.3d 1022, 1026 (6th Cir. 1994)). The district court properly certified its 2014 grant of partial summary judgment to DTE for immediate appeal under Rule 54(b) because the district court entered final judgment on EPA's and Sierra Club's claims relating to DTE's 2010 construction projects at Monroe Unit #2. The remaining claims by EPA and Sierra Club involved DTE's completion of distinct, unrelated construction projects. Further, the district court did not abuse its discretion in concluding that there was no just reason to delay immediate appellate review of its grant of partial summary judgment.

alleged that DTE failed to comply with the express regulatory requirements for making projections by: (1) failing to consider all relevant information when making its projection; (2) improperly applying the demand growth exclusion; and (3) failing to explain its use of the demand growth exclusion. In order to be excluded under the demand growth exclusion, an emissions increase must be unrelated to the operator's proposed project. 40 C.F.R. § 52.21(b)(41)(ii)(c). An emissions increase is not related to the project if the increase is caused by growth in demand for electricity after the project is complete. *DTE Energy Co.*, 711 F.3d at 646. However, an emissions increase is related to the proposed project if the increase is caused by improved reliability, lower operating costs, or other improved operational characteristics of the unit after the project is complete. 61 Fed. Reg. 38,250, 38,268 (July 23, 1996). EPA claims that DTE excluded all of its predicted emissions under the demand growth exclusion even though DTE's computer modeling and project documents predicted that the operational improvements at Monroe Unit #2, rather than an increased demand for electricity, would cause these increased emissions. EPA therefore contends that DTE violated the express requirements of the regulations by excluding emissions that were related to DTE's proposed projects.

Contrary to EPA's contention, there is no genuine issue of material fact about whether DTE's projection complied with the basic requirements for making projections. EPA does not contend that DTE violated the regulations by failing to make any projection. Nor does EPA contend that DTE violated the basic requirements of the regulations. Rather, EPA questions: (1) DTE's interpretation of the relevant information; (2) the methodology that DTE used to reach its conclusion that its predicted emissions increase could be excluded under the demand growth exclusion; and (3) the adequacy of DTE's explanation of why it reached this conclusion.

First, there is not a genuine issue of material fact about whether DTE violated the basic requirements of the regulations by ignoring relevant information. The regulations governing projections require an operator to "consider all relevant information" in determining its projected actual emissions, including but not limited to "the company's expected business activity" and "the company's filings with State or Federal regulatory authorities." 40 C.F.R. § 52.21(b)(41)(ii)(a). EPA claims that DTE ignored the relevant information because DTE created a "best estimate" computer model that reflected DTE's expected business activity and filings with a state regulatory authority but that DTE then ignored this model when it claimed that its predicted emissions increase was unrelated to its projects. EPA Br. at 39. To support this contention, EPA argues that running DTE's "best estimate" computer modeling with and without the changes caused by the projects showed that DTE's predicted emission increase would be caused by increased availability of Monroe Unit #2 after the projects were complete. *Id.* at 36–37. EPA claims that DTE ignored this modeling when claiming that its predicted increase was unrelated to the projects. EPA contends that DTE instead relied on its principal environmental engineer's "unsubstantiated" belief that a boiler tube component replacement project—like the economizer replacement at issue here—could not cause an emissions increase. *Id.* at 39.

This argument does not show that DTE violated the basic requirements of the regulations by failing to consider all relevant information. This claim is premised upon EPA's attempt to challenge the validity of DTE's conclusion that its predicted emissions increase was unrelated to its proposed projects. EPA does not contend that DTE failed to consider particular sources of relevant information when it created its computer modeling because EPA agrees that DTE's projection was based on a "'sophisticated' computer model" that considered "'exhaustive' inputs." United States Br. at 13. Accordingly, EPA's complaint at bottom is not that DTE failed to consider all the relevant information. Rather, EPA contends that DTE must have misinterpreted the relevant information in order to conclude that its projected increase was unrelated to the projects. The regulations for making projections do not state that an operator must interpret relevant information in a certain way or arrive at certain conclusions after examining relevant information. Error in interpretation of information is not, in short, failure to consider information.

Similarly without merit is Sierra Club's contention that DTE violated the regulations by failing to consider a projection that DTE submitted to the Michigan Public Service Commission. Sierra Club Br. at 13–14. This projection, which was based upon the same PROMOD modeling that DTE used to make its preconstruction projection, projected lower annual system energy demand in each of the five years after the projects than in each of the five years before the projects. Sierra Club contends that DTE's projection that the demand would decline in its overall system is inconsistent with its projection that demand for Monroe Unit #2 would increase. Sierra Club Br. at 13–14. It is true that DTE's statement to EPA that the projected emissions increase at Monroe Unit #2 was due in part to an "an increase in demand for the system as a whole" appears to be inconsistent with DTE's projection to the Michigan Public Service Commission that its annual system energy demand would decrease after the projects were complete. However, as stated above, DTE concluded that its projected increase in emissions at Monroe Unit #2 was due in part to the fact that this unit would need to generate more energy in 2013 to help make up for an extended outage of Monroe Unit #1 in 2013. DTE therefore could have projected that demand for energy at Monroe Unit #2 would increase in 2013, even if the demand for energy in DTE's overall system decreased. The Sierra Club therefore does not show that DTE failed to consider all relevant information in order to conclude that its projected emissions increase was unrelated to the projects.

Second, there is not a genuine issue of material fact about whether DTE followed the basic methodological requirements of the regulations when DTE excluded its predicted emissions increase under the demand growth exclusion. The demand growth exclusion provides that in making a preconstruction projection, an operator shall exclude the portion of the unit's emissions following the project that "could have [been] accommodated" during the baseline period and that are "unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(c). EPA contends that DTE improperly applied the demand growth exclusion because DTE excluded all of its predicted emissions increase under this exclusion even though its computer modeling and project documents demonstrated that much of its predicted emissions increase was related to the projects. EPA Br. at 36–37; EPA Reply Br. at 24. To support this assertion, EPA relies on its expert witness Philip Hayet's opinion that an analysis of DTE's computer modeling showed that Monroe Unit #2 would break down less after the projects were complete and would be able to generate more electricity and emissions. To reach this conclusion, Hayet used a "standard industry methodology" that ran DTE's model with and without the effects of the projects while keeping all other inputs the same. EPA also contends that, like DTE's computer modeling, DTE's project documents predicted that the Monroe Unit #2 would generate more electricity and pollution after the projects were complete because Monroe Unit #2 would break down less frequently. EPA Br. at 37.

However, EPA does not point to any rule in the regulations that establishes that DTE is required to perform Hayet's "standard industry methodology" in order to evaluate whether the predicted emissions could be excluded under the demand growth exclusion. Similarly, EPA does not point to any language in the regulations that establishes the weight that DTE is required to place on its project documents when determining whether predicted emissions can be excluded under the demand growth exclusion. EPA also does not point to language in the regulations that sets forth rules for how DTE should interpret its project documents.

The issue of whether the demand growth exclusion applies to an operator's predicted emissions increase "is a fact-dependent determination that must be resolved on a case-by-case basis." *DTE Energy*, 711 F.3d at 646 (quoting 57 Fed. Reg. 32,314, 32,327 (July 21, 1992)). Accordingly, requiring DTE to establish that its application of the exclusion was more reasonable than EPA's application of the exclusion would turn New Source Review into a *de facto* prior approval scheme by requiring a district court to hold a trial to resolve this issue before the operator could proceed to construction. EPA therefore cannot show that DTE violated the regulations for applying the demand growth exclusion by contending that EPA would have applied this exclusion differently if EPA had been tasked with making the projection.

EPA also relies on EPA guidance about what it means for an emission to be "unrelated" to a project to support its argument that DTE violated the regulations by excluding a portion of DTE's projected emissions increase, which the regulations provide cannot be excluded. This reliance is misplaced. EPA repeatedly cites its statement that an increase in emissions must be "completely unrelated" to an operator's proposed project in order to be excluded under the demand growth exclusion. EPA Br. at 9, 28, 34–35. This statement does not provide operators with instructions about how to determine whether predicted emissions were completely unrelated to proposed projects. This statement also does not codify the methodology that EPA used to determine that DTE's predicted emissions increase was related to its proposed projects. Accordingly, this statement does not establish that DTE violated the regulations for applying the demand growth exclusion.

EPA's reliance on a statement in a preamble to proposed rulemaking from 1996 is similarly misplaced. In this preamble, EPA stated that when "the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (July 23, 1996). EPA seizes upon this language to contend that DTE's prediction that the projects would increase availability and reliability at Monroe Unit #2 is sufficient to establish that DTE's projected emissions increase was related to the projects. EPA Br. at 28, 37. This contention fails because EPA ignores its statement in the preamble that it "declined to create a presumption that every emissions increase that follows a change in efficiency . . . is inextricably linked to the efficiency change." 61 Fed. Reg. at 38,268.

Other EPA guidance also establishes that an emissions increase that follows a change in a unit's reliability or availability is not necessarily related to that change. In particular, in analyzing the 1992 New Source Review rules, EPA observed that "there is no specific test available for determining whether an emissions increase indeed results from an independent factor such as demand growth, versus factors relating to the change at the unit." 63 Fed. Reg. 39,857, 39,861 (July 24, 1998). The EPA therefore suggested not allowing operators to exclude "predicted capacity utilization increases due to demand growth from their predictions of future emissions." *Id.* However, EPA did not remove the demand growth exclusion. Instead, EPA kept the exclusion, recognizing that New Source Review record-keeping requirements establish "an adequate paper trail to allow enforcement authorities to evaluate [an operator's] claims concerning what amount of an emissions increase is related to the project and what amount is attributable to demand growth." 72 Fed. Reg. 72,607, 72,611 (Dec. 21, 2007).

Third, EPA's assertion that DTE violated the regulations by failing to properly explain why it excluded all of its projected emissions increases lacks merit. The regulations require an operator to "document and maintain a record of . . . the amount of emissions excluded" under the demand growth exclusion and "an explanation for why such amount was excluded" before beginning construction on a project. 40 C.F.R. § 52.21(r)(6)(i)(c). EPA contends that DTE violated this requirement by sending state regulators a letter that asserted that the demand growth exclusion applied to its predicted emissions increase without providing any factual support for this assertion. EPA Br. at 32–35.[4]

As the district court noted, although DTE's explanation of its use of the demand growth exclusion is not very detailed and "the accompanying table shows the results of the calculations without their back-up data, [EPA] does not point to any provision in [Michigan's equivalent to the New Source Review] rules requiring specificity beyond that which was provided." EPA also does not point to any regulation that describes the amount of detail that an operator is required to include in order to comply with the requirement to maintain an explanation of the operator's use of the demand growth exclusion. Allowing an enforcement action in this context would effectively turn the New Source Review into a *de facto* prior approval system.

EPA and Sierra Club's other arguments in support of allowing this enforcement action to continue are also unavailing. EPA contends that requiring it to defer to an operator's judgment about the projection itself and about whether the demand growth exclusion applies to the operator's predicted emissions increase would result in a voluntary New Source Review program for existing sources. To support this assertion, EPA claims that it will not be able to effectively evaluate potential increases in air pollution if the reasonableness of the projection and the applicability of the demand growth exclusion are "left to the source's unfettered discretion." EPA Reply Br. at 28. However, forbidding EPA from challenging an operator's projection on the basis that EPA would have used different methodology to create the projection or would have reached a different conclusion about whether the demand growth exclusion applied to the operator's predicted emissions increase is not equivalent to leaving the applicability of the demand growth exclusion and the making of the projection to the sole discretion of the operator. Rather, EPA can still challenge operators who fail to follow the basic requirements of the regulations by failing to make and record their preconstruction projections, by providing no

[4]EPA contends that it did not allege that DTE had failed to comply with § 52.21(r)(6)(i)(c). EPA Reply Br. at 24 n.2. However, EPA claimed that DTE did not provide an "explanation" to support its exclusion of its projected emissions as required under § 52.21(r)(6)(i)(c) and claimed that DTE had not adequately supported its claim that the projected emissions increase could be excluded under the demand growth exception. EPA Br. at 32–35. Accordingly, EPA's allegation that DTE failed to adequately support its use of the demand growth exclusion appears to be based upon EPA's contention that DTE violated the requirement to provide an adequate explanation of its use of the demand growth exclusion under § 52.21(r)(6)(i)(c).

explanation for their applications of the demand growth exception, or by excluding predicted emissions that the operators conclude are related to their projects.

EPA further contends that requiring it to defer to an operator's judgment about whether a predicted emissions increase can be excluded under the demand growth exclusion would require EPA to also defer to the operator's determination about whether an actual increase in emissions could be excluded under the demand growth exclusion. EPA Reply Br. at 28–29. This assertion is unavailing. This court's prior opinion did not foreclose EPA from challenging the reasonableness of an operator's determination that an actual post-construction increase in emissions was unrelated to the project. To the contrary, this court explained that "[a]n operator takes a major risk if it underestimates projected emissions" because the operator will face large penalties "[i]f post-construction emission are higher than preconstruction emissions, and the increase does not fall under the demand growth exclusion." *DTE Energy*, 711 F.3d at 651. Accordingly, this court's prior opinion indicates that EPA does not need to defer to an operator's determination about whether an actual increase in emissions after construction was related to the project.

EPA also contends that *Alaska Dep't of Envtl. Conservation v. EPA* establishes that EPA can also challenge the reasonableness of DTE's preconstruction projection. EPA Reply Br. at 21–23. This contention fails. In *Alaska Dep't*, the Supreme Court held that EPA can evaluate whether a state's imposition of pollution controls in an operator's permit was "reasonably moored to the [Clean Air] Act's provisions." 540 U.S. 451, 485, 488–90 (2004). Unlike DTE's projection, which was made before DTE decided whether it needed to obtain a permit, the pollution controls in *Alaska Dep't* were created after the operator had independently concluded that it had to obtain a permit before beginning construction. *Id.* at 474–75. EPA's ability in *Alaska Dep't* to challenge the reasonableness of pollution controls included in a permit did not turn New Source Review into a *de facto* prior approval scheme by allowing EPA to "in effect . . . require prior approval of [an operator's] projections." *DTE Energy*, 711 F.3d at 649. *Alaska Dep't* is therefore inapposite.

EPA and Sierra Club also contend that EPA's enforcement action must be allowed to continue because a ruling in DTE's favor would harm public health and the economy. To support this assertion, EPA and Sierra Club explain that DTE's conclusion that it was not required to obtain a permit before beginning construction allowed it to delay installing updated pollution controls in Monroe Unit #2 for four years. Sierra Club Reply Br. at 21–21; EPA Br. at 53. EPA and Sierra Club contend that the increased pollution resulting from this delay resulted in "approximately 90 premature deaths and total social costs of $500 million" each year that the pollution controls were delayed. Sierra Club Reply Br. at 21; EPA Br. at 53–54. As this court previously explained, New Source Review is not designed to "force every source to eventually adopt modern emissions control technology." *DTE Energy*, 711 F.3d at 650. Accordingly, the fact that DTE was able to delay imposing updated pollution controls by "keep[ing] its post-construction emissions down in order to avoid the significant increases that would require a permit" is "entirely consistent with the statute and regulations." *Id.*

The district court relied additionally on the fact that post-project emissions did not actually increase. The underlying purpose of the statutory and regulatory scheme of permitting improvements that do not increase emissions therefore appears to have been met. However, because the undisputed facts establish that DTE complied with the basic requirements for making projections, I do not rely on the district court's alternative reason for granting summary judgment.

I would affirm the district court's judgment.

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

Nos. 14-2274/2275

UNITED STATES OF AMERICA (14-2274),
Plaintiff - Appellant,

SIERRA CLUB (14-2275),
Intervenor Plaintiff - Appellant,

v.

DTE ENERGY COMPANY and DETROIT EDISON COMPANY,
Defendants - Appellees.

FILED
Jan 10, 2017
DEBORAH S. HUNT, Clerk

Before: BATCHELDER, DAUGHTREY, and ROGERS, Circuit Judges.

JUDGMENT

On Appeal from the United States District Court
for the Eastern District of Michigan at Detroit.

THIS CAUSE was heard on the record from the district court and was argued by counsel.

IN CONSIDERATION WHEREOF, it is ORDERED that thedistrict court's grant of summary judgment to DTE Energy Company is REVERSED, and the case is REMANDED for further proceedings consistent with the opinion of this court.

ENTERED BY ORDER OF THE COURT

Deborah S. Hunt, Clerk

PAL Contribution based on Emissions Unit Status

Case	Emissions Unit Status: Baseline Period	Emissions Unit Status: Application Submittal Date	PAL Contribution	Regulatory Reference (40 CFR 52.21)	Notes
1	N/A	New	PTE	(aa)(6)(i); (b)(48)(iii),(iv); (b)(7)	Is or will be newly constructed • Operated < 2 years as of application date; • Permit obtained, construction commenced prior to application date
2	In existence*	Existing	24-month average annual emissions	(aa)(6)(i); (b)(48)(i),(ii),(iv)	Must incorporate all required downward adjustments and address qualifying criteria under (b)(48)
3		Shut down	Zero	(aa)(6)(i)	In accordance with §52.21(aa)(6)(i), emissions associated with units that were permanently shut down after the baseline period must be subtracted from PAL level.
4	Not in existence*	Existing or new; actual construction began after baseline period	PTE	(aa)(6)(ii)	

* "In existence" as used here means any unit that existed during the baseline period, including any unit on which actual construction began prior to end of baseline period. This should not to be confused with "existing," which means "existing emissions unit" as defined in the regulations.

<u>Relevant excerpts from 40 CFR 52.21</u>

(b)(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

(b)(48) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

. . .

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

. . .

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(48)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(48)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(48)(iii) of this section.

(aa)(6) *Setting the 10-year actuals PAL level.* (i) Except as provided in paragraph (aa)(6)(ii) and (iii) of this section, the plan shall provide that the actuals PAL level for a major stationary source or a GHG-only source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(48) of this section or, for GHGs, paragraph (aa)(2)(xiii) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_x to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(ii) For newly constructed units (which do not include modifications to existing units) on which actual construction began after the 24-month period, in lieu of adding the baseline actual emissions as specified in paragraph (aa)(6)(i) of this section, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

. . .

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

December 6, 2016

Harry M. Wilson III, P.E., DEE
Chief, Environmental Permits Division
Mississippi Department of Environmental Quality
Post Office Box 2261
Jackson, Mississippi 39225-226

Dear Mr. Wilson:

Thank you for sending the Prevention of Significant Determination (PSD) application for a proposed project at Roxul USA, Inc. (Marshall County), Mississippi. The application is for a modification to an existing PSD permit issued on February 25, 2014.

Based on review of the PSD application and modeling information, the U.S. Environmental Protection Agency submitted air quality modeling comments to Mississippi Department of Environmental Quality (MDEQ) staff by email on October 17, 2016. Also, during an October 26, 2016, conference call with MDEQ, a number of unresolved air quality impact modeling issues with the Roxul USA PSD permit application were identified and discussed. The EPA Region 4 strongly recommended that these issues be resolved prior to MDEQ initiating the public comment period for the draft PSD permit preliminary determination.

Since MDEQ did not fully address the EPA's comments prior to the public comment period, the EPA continues to recommend that the following comments be resolved prior to issuance of the final PSD permit:

1. Roxul used the non-regulatory default option (i.e., Adjust U* beta option) in the AERMOD modeling analysis without obtaining approval from EPA as required . The regulatory application of any of the Beta options in AERMOD/AIRMET version 15181 require formal approval as an alternate model subject to the requirements of Appendix W of 40 CFR 51, Section 3.2.2. (i.e., Use of Alternative Models). Further guidance is provided in the EPA Memorandum: Clarification on the Approval Process for Regulatory Application of the AERMOD Modeling System Beta Options (December 10, 2015). Approval of a non-regulatory default option from the EPA Regional Office, which includes consultation and concurrence with the Model Clearinghouse, was not obtained. Therefore, the air quality impact modeling analyses supporting this PSD permit application are not an acceptable demonstration that the proposed project's emissions will not cause or contribute to impacts exceeding the all current ambient air quality standards (i.e., National Air Quality Standards and PSD increments).

2. A number of the EPA's review comments regarding the application's air quality assessment remained outstanding at the time the public notice period began for the draft PSD permit preliminary determination. These comments requested additional information and clarification or verification of information provided in the application to facilitate a complete assessment of the air quality assessment. Although Roxul provided responses to these comments just prior to start of the public comment period, the EPA was not provided adequate time for verification of the resolution of the remaining comments before the beginning of MDEQ's public comment period for this permit application.

If you have any questions about these comments or require additional information, please contact James Purvis at (404) 562-9139 or Stan Krivo at (404) 562-9123.

Sincerely,

Heather Ceron

Heather Ceron
Chief
Air Permitting Section

ROXUL MODELING STATUS SUMMARY AS OF DECEMBER 2016

BACKGROUND INFORMATION

Roxul USA, Inc. (Roxul), a subsidiary of Rockwool International A/S, owns and operates an existing mineral wool insulation manufacturing facility located in Byhalia, Mississippi. The facility produces mineral wool insulation and associated products. Operations at the facility comprise two Mineral Wool insulation manufacturing lines, a Recycle Plant to process recycled materials into a "brick" raw material, a Bitumen Line to produce roofing insulation, a Rockfon Line to produce ceiling tiles, and associated ancillary operations. Construction was to be completed in two (2) two phases:

Phase I - Construction of the Mineral Wool Line 1 and the Recycle Plant;

Phase II - Construction of the Mineral Wool Line 2, the Bitumen Line and the Rockfon Line.

The initial Prevention of Significant Deterioration (PSD) Construction Permit was issued August 22, 2012, and later modified February 25, 2014.

PROJECT DESCRIPTION

Roxul submitted an application for a modification of the facility's existing PSD Construction Permit on May 27, 2016. The proposed project included design updates to the Rockfon Line, the addition of two (2) new processes (a Dry Ice Cleaning Process and a Fleece Application Process), and the permitting of minor ancillary emission sources that were not anticipated at the time of the initial PSD permit application. An update to the May 2016 submittal was submitted September 13, 2016. The September 2016 application update comprised the following:

- Updates to proposed BACT limits
- Updates to proposed compliance demonstration for emission sources
- Updates to emission calculation
- BACT evaluation for emission sources associated with the Rockfon Coating process; and
- Updates to stack parameters consistent with the ***"Volume II Dispersion Modeling Report, August 2016"***.

Air pollutant dispersion modeling was performed for the entire facility, including the proposed modifications addressed by this application, in accordance with Mississippi PSD regulation 11 Miss. Admin. Code Pt. 2, Ch. 5. Modeling was performed to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS), as adopted by 11 Miss. Admin. Code Pt. 2, Ch. 4., and the PSD increments.

AIR DISPERSION MODELING REVIEW SUMMARY

In the Air Quality Assessment Protocol, Roxul proposed use of the beta alternative formulation of surface friction velocity (u*) non-regulatory default option (ADJ_U*) in AERMET version 15181 as the meteorological processor for AERMOD version 15181 for this modeling. The non-regulatory default option ADJ_U* was included as a specific procedure in the air quality modeling (Volume II: Update to PSD Air Quality Assessment). Roxul included justification for use of the beta adjust u* options in AERMET in the modeling protocol. The submittal was prepared by Environmental Resources Management (ERM) on behalf of Roxul USA, Inc.

The PSD Air Quality Analysis was received August 22, 2016. Stan Krivo, EPA Region 4, provided modeling review comments to Roxul via email on October 21, 2016. An October 25, 2016 conference call was scheduled to discuss the modeling review comments from EPA Region 4 and MS DEQ. Discussions included actions and information needed to appropriately resolve each comment. Conference Call Attendees: Roxul USA, Inc. (Sharon Taylor), EMR Consultants, MDEQ (Jacqueline Evans), and EPA Region 4 (Stan Krivo).

MODELING REVIEW COMMENT – METEOROLOGICAL DATA

The regulatory application of any of the Beta options in AERMET or AERMOD versions 15181 required formal approval as an alternative model and are subject to the requirements of Appendix W, Section 3.2.2 Use of Alternative Models – Recommendations. [EPA Memorandum: Clarification on the Approval Process for Regulatory Application of the AERMOD Modeling System Beta Options, December 10, 2015]. Approval of a non-default option from the Regional EPA office, which also requires concurrence of the Model Clearinghouse, should have been obtained before inclusion as a specific procedure in the modeling analysis. Roxul USA, Inc.'s performed the modeling analysis with the beta adjust u* option without prior formal approval from EPA Region 4.

EPA Region 4 did not deny or disapprove Roxul's justification for use of the beta adjust u* option, but requested additional information that would demonstrate the appropriateness of this non-default option for this application. Roxul indicated that the information had been compiled, but not included in the initial submittal. Roxul was directed to the Model Clearinghouse Information Storage and Retrieval System (MCHISRS) and EPA's Support for Regulatory Atmospheric Modeling (SCRAM) websites containing previous ADJ_U* applications and approvals for examples of the information/analyses needed for this demonstration.

ROXUL USA, INC., RESPONSE:

In response to the modeling review comment, Roxul provided additional information that supports their request for approval, the application of ADJ_U* in AERMET version 15181. Roxul provided a demonstration that use of the beta option incorporated into the AERMOD Modeling System performs better than the default regulatory version of AERMOD for this specific application where high modeled concentrations are likely to occur under low wind, stable conditions. Starting in version 12345, AERMOD has included non-regulatory default options to address concerns regarding model performance under low wind speed conditions. In the current formulation, the model routinely under predicts u* during stable boundary layer conditions under low wind speeds resulting in an overestimate in concentrations. The ADJ_U* option addresses these concerns.

Roxul's submittal comprised an updated discussion/comparison of the change in predicted concentrations (AERMOD default scenario vs AERMOD non-default), location or receptors of concern, and model results.

MDEQ RESPONSE:

MDEQ reviewed the updated *"Justification for Application of the ADJ_U* Beta Option in AERMET"* with the addition of the supplemental information requested by EPA Region 4. Roxul USA, Inc.'s submittal, the updated *Justification for Application of the ADJ_U* Beta Option in AERMET,* appears to be complete and provides support/technical information consistent with similar requests for approval of an alternative model. Specifically, use of Surface Friction Velocity (ADJ_U*) Non-Regulatory Default Option in AERMET/AERMOD version 15181. The Justification for Application of the ADJ_U* Beta Option in AERMET with supplemental information has been provided to EPA Region 4 as required for review/comment and submission to the Modeling Clearinghouse for approval. MDEQ believes that the use of the beta option satisfies Appendix W, Section 3.2.2, that the alterative model performs better for the given application than the comparable in Appendix A.

MODELING REVIEW COMMENTS – GENERAL COMMENTS

Twenty-four (24) general comments comprising requests for additional information, clarification, and/or verification of information provided in the air quality assessment were provided to Roxul. Such as, but not limited to, providing a map/site plan that clearly shows the fence line, providing MAXDCONT files showing Roxul's contribution to modeled concentrations, verifying all maximum concentrations were modeled to 100-m spacing, providing supporting documentation for excluding emergency generator and fire pump from modeling, verifying maximum hourly emission rates and stack parameters, etc…

ROXUL USA, INC., RESPONSE

Roxul provided responses to comments (***Response to Air Quality Review Comments*** document) in an email dated October 28, 2016.

MDEQ RESPONSE

Upon complete review of Roxul's ***Response to Air Quality Review Comments*** document received October 28, 2016, MDEQ and Region 4 EPA will provide their evaluations.

PUBLIC NOTICE/COMMENT PERIOD

MDEQ announced the 30-day public comment period with a public notice published on November 2, 2016.

Formal approval of an alternative model, specifically, use of Surface Friction Velocity (ADJ_U*) Non-Regulatory Default Option in AERMET/AERMOD version 15181 was ***pending***. MDEQ believed that the supplemental information provided by Roxul USA, Inc., was complete and provided additional support/technical information consistent with similar requests for approval of an alternative model. MDEQ believed that the use of the beta option would satisfy Appendix W, Section 3.2.2. The following statement was included in the preliminary determination and public notice documents:

Based on information received from EPA Region 4, MDEQ expect approval before the end of the public comment period. Please be advised, should the public comment period end before approval is obtained and/or adverse comments are received, the draft permit will not be signed until alternative model use approval is obtained and/or adverse comments are resolved.

EPA Region 4 APTMDHot Issue Paper1/27/17

<u>ISSUE</u>: Mississippi – Roxul USA CAA Permit

<u>SUMMARY</u>: In May 2016, Roxul USA submitted an application (subsequently updated) for a modification of its Byhalia, MS, wool insulation manufacturing facility's existing Prevention of Significant Deterioration (PSD) Construction Permit. EPA Region 4 commented on the PSD application and draft permit, including the air dispersion modeling performed as part of the application. Within the public notice, MDEQ indicted that the modeling had not been approved by EPA and that MDEQ would not issue the permit until they received EPA's approval. The company provided a revised modeling analysis on January 19, 2017, and MDEQ indicated that they would like to issue the permit on 1/27/17. Our modeling staff worked quickly to respond to the revised modeling analysis and provided comments yesterday, 1/26/17. There have been many communications with MDEQ and the modeling contractor to support their efforts in addressing our comments. MDEQ will not be issuing the permit today but hopes to early next week. Employees from the company's home office in Denmark plan to travel to the plant once the permit is issued to begin to implement the changes.

<u>BACKGROUND</u>: Roxul is a wool insulation manufacturing facility located in Byhalia, MS. The company submitted an application for a modification of the facility's existing PSD Construction Permit on May 27, 2016 (with an additional update on September 13, 2017). The proposed modification included design updates to the "Rockfon Line" (source number AA-500), the addition of two new processes (a dry ice cleaning process and a fleece application process), and the permitting of minor ancillary emission sources that were not anticipated at the time of the original PSD permit application.

EPA Region 4 commented on the PSD application and draft permit in August 2016 and in October 2016, we provided comments on the modeling analysis performed in support of the permit modification. A revised modeling analysis was provided to EPA Region 4 on 1/19/17. EPA Region 4 responded with follow-up comments on the revised modeling analysis on 1/26/17. These follow-up comments have yet to be addressed.

MDEQ opened the draft permit for public review from 11/4/17 to 12/7/17. Within the public notice for the draft permit, MDEQ indicated that the air quality modeling analysis prepared in support of the permit modification had not yet been approved by EPA and that MDEQ would not issue the permit until they received EPA's approval. As noted above, EPA's comments on the modeling analysis have not been fully addressed; however, MSDEQ has stated their desire to issue the permit by 1/27/17.

<u>NEXT STEPS</u>: MDEQ is continuing to work with the facility's modeling contractor to address both EPA and MDEQ's comments. We understand that the contractor is planning to take the weekend to complete the modeling runs, so we will not have the sulfur dioxide (SO2) modeling portion until Monday.

EPA, MDEQ, and the modeling contractor are scheduled to have a call on 1/27/17 at 4:30pm ET. Region 4 is closely coordinating with EPA's Office of Air Quality Planning and Standards as we work towards resolution of these outstanding modeling issues.

Status of NSR/Title V Rule-related Actions

As of 1/25/2017

A. Rules finalized within the past 6-months

1. **Regional Consistency Rule Amendments.** Revise 40 CFR Part 56 to allow an exception to the regional consistency regulation for certain judicial decisions. FR publication August 3, 2016 (81 FR 51102). (Greg Nizich)

2. **$PM_{2.5}$ NSR Implementation Rule.** Changes include adding new major source thresholds for $PM_{2.5}$ and $PM_{2.5}$ precursors in Serious Areas, a requirement to control 4 $PM_{2.5}$ precursors for NNSR (no change for PSD), and a recommended methodology in the form of EPA guidance for exempting a $PM_{2.5}$ precursor when it does not significantly contribute to $PM_{2.5}$ concentrations in a particular nonattainment area. The rule was signed on July 29, 2016, and published in the FR on August 24, 2016. The rule was effective on October 24, 2016.

3. **Revisions to Public Notice Requirements for Clean Air Act Permitting Programs.** The rule will revise the public noticing rule provisions for the Title V, NSR and OCS permit programs. The rule will remove the mandatory requirement for a permitting authority to provide notice of a permitting action through publication in a newspaper and to instead provide for noticing of permits electronically on agency websites (i.e., electronic notice, or "e-notice"). The rule will describe what is required to provide electronic notice of a proposed permit action as well as electronic access to the draft permit. Rule signed Oct 5, 2016, Published in FR Oct 18, 2016 (Peter Keller/Ben Garwood)

4. **Permit Rescission Rule Revision.** This rulemaking will revise the existing "permit rescission" provision at 40 CFR 52.21(w). The current rule allows a permittee to request that EPA rescind their PSD permit if: (1) they can show that PSD does not apply, and (2) the permit was issued under rules that were in effect on or before July 30, 1987. This rule will allow for rescission of a PSD permit issued under post-7/30/1987 rules and will clarify the types of permitting scenarios that are most suitable for rescission. FR Publication June 14, 2016 (81 FR 38640). Comment period closed on July 14, 2016. We received 6 comments (1 industry, 2 states, 3 industry associations) Overall the commenters were in favor of the proposed change because the removal of the date restriction will allow a PSD permit holder the ability to request that EPA or a delegated permitting authority rescind a permit that would no longer be required in circumstances such as an EPA change to the PSD regulations or a court decision that narrows the scope of the PSD program. A few commenters wanted us to specify other circumstances under which a PSD permit rescission might be granted, while a couple of other commenters would like us to use this rule to specify that PSD permits that were issued before the promulgation of the 2007 final Ethanol Rule can be rescinded. Tier 3. Rule Signed October 26, 2016. (Jessica Montanez).

B. Final Rule Stage (Includes proposed rules following close of the comment period and direct final rules in development)

5. **Removal of Title V Emergency Affirmative Defense Provisions.** This rulemaking is being conducted in order to remove the "emergency provisions" form both sets of Title V implementing regulations: 40 CFR 70 (State Operating Permit Programs) and 40 CFR 71 (Federal Operating Permit Programs). The regulations for the title V permitting program currently provided for an affirmative defense to actions brought for noncompliance with technology-based emission limits that result from an alleged emergency. The emergency provisions are legally vulnerable as explained in D.C. Circuit decisions and in detail as part of the SSM SIP Call final action; this rule is essentially a follow-up to the SSM SIP Call. In addition to removing these provisions form our regulations, this action will require some implementation actions relating to state permitting programs and individual title V permits that contain similar provisions. Published in Federal Register on June 14, 2016, 81 FR 38645. Final rule on hold pending Headquarter direction. (Matt Spangler)

6. **Establishment of Significant Emission Rate (SER) for Greenhouse Gases under the PSD Permitting Program and Revisions to the Tailoring Rule Provisions**. This proposal revises provisions applicable to GHG in the PSD and title V permitting regulations. This action is in response to the June 23, 2014, Supreme Court's decision in *Utility Air Regulatory Group (UARG) v. EPA* and the April 10, 2015, Amended Judgment by the D.C. Circuit in *Coalition for Responsible Regulation v. EPA*. The proposed PSD and title V revisions involve changes to several regulatory definitions in the PSD and title V regulations, revisions to the PSD provisions on GHG PALs, and revisions to other provisions necessary to ensure that neither the PSD nor title V rules require a source to obtain a permit solely because the source emits, or has the PTE, GHGs above the applicable thresholds. In addition, the EPA is also proposing a SER for GHGs under the PSD program that would establish an appropriate threshold level below which BACT is not required for a source's GHG emissions. Proposal signed on August 26, 2016 with publication in the FR on October 3. Comment period closed on December 2, 2016, comments are currently being reviewed. (Jessica Montanez/Carrie Wheeler).

C. Proposed Rule Stage (Includes rules planned to be proposed and proposed rules through the comment period).

7. **Revisions to the Petition Provisions of the Title V Permitting Program.** This proposal identifies mandatory guidelines on the substance and format of title V petitions submitted to the Agency as well as requirements for the electronic submittal of title V petitions by the specific method identified in the rule. It sets forth a more detailed process for the EPA review of title V petitions, next steps following the EPA action on a petition, and mandated minimum contents of a petition. In addition, the proposal may provide a greater level of engagement with state and local permitting authorities concerning the EPA's review of a petition

regarding state and local title V permits. FR publication August 24, 2016 (81 FR 57822). Comment period closed October 24, 2016; comments currently being reviewed (Carrie Wheeler).

8. **2015 Ozone Implementation Rule.** The proposal describes how obligations to implement anti-backsliding requirements pertaining to NSR thresholds and offset ratios under the 1-hour and 1997, and 2008 8-hour ozone NAAQS can be terminated in light of revocation of the 1 hour and 1997 ozone NAAQS and the impending revocation of the 2008 NAAQS. When the previous NAAQS are revoked, the nonattainment designations will nevertheless be retained in 40 CFR part 81 as a reference for anti-backsliding purposes. The retention of such references is not intended to affect the applicability of PSD in areas that are designated attainment or unclassifiable for the 2015 ozone NAAQS. The overall construct for the rule will be as an update to reflect the latest 2015 ozone NAAQS while including more detailed discussion on tailored issues for NSR including interprecursor trade rule language as part of the pending petition for reconsideration noted below. Proposed Rule signed November 2, 2016, and published November 17, 2016 (81 FR 81276). Public hearing requested by API (1/12/17) with comment period through February 13, 2017. (Ben Garwood).

D. *Reconsiderations*

9. **Ozone Interprecursor Trading Provision (IPT).** The final 2008 ozone SIP Requirements Rule (SRR) included rule language established through logical outgrowth from the proposal addressing IPT that prior to the amended rule language could be interpreted to restrict interprecursor trade to PM only. On May 5, 2015, a petition for reconsideration was filed by a coalition of environmental and health advocate groups. A petition for reconsideration was granted by EPA on November 5, 2015. Currently, the Agency is planning to address IPT in the 2015 Ozone Implementation Rule. (Ben Garwood)

E. *Guidance/Other*

10. **Draft Ozone and $PM_{2.5}$ Significant Impact Level (SILs) Guidance for PSD Program.** The draft guidance establishes a SIL for ozone and re-establishes SILs for $PM_{2.5}$. These SILs can facilitate implementation by providing a possible compliance demonstration tool for each form of the $PM_{2.5}$ standard and the 8-hour ozone standard in attainment and unclassifiable areas. The draft guidance can be found at (https://www.epa.gov/nsr/forms/significant-impact-levels-ozone-and-fine-particles-prevention-significant-deterioration). Informal comment period closed on September 30, 2016. NSRG is working with OGC and AQMG to review comments and modify guidance as required. Final guidance signature date still TBD. (Jen Shaltanis/Chuck Buckler)

11. **$PM_{2.5}$ NSR Implementation Rule Precursor Demonstration Guidance.** This guidance supplements The Rule and provides the process in which permitting authorities can opt out for one or more of the $PM_{2.5}$ precursors. Draft guidance

went out Nov 18 for review until January 31, 2017. The link to review is: https://www.epa.gov/pm-pollution/draft-pm25-precursor-demonstration-guidance Dan Deroeck/Chuck Buckler)

F. *Pending Actions*

12. **NSR Aggregation Rule.** The effective date of the 2009 aggregation rule is postponed indefinitely, pursuant to APA section 705, while litigation is pending; see notice published 5/18/10 at 75 FR 27643. (Dave Svendsgaard)

13. **NSR Reasonable Possibility Rule.** Final rule, published 12/21/07 (73 FR 72607), clarifies the "reasonable possibility" standard of the December 2002 NSR Reform rules. By 4/24/09 letter from the Administrator, we granted reconsideration on the petition of 2/15/08 submitted on behalf of the State of New Jersey (and reiterated in petitioner's letter of 3/11/09). We decided not to stay the rule. (Cheryl Vetter)

14. **Fugitive Emissions Rule Reconsideration.** NRDC declined to withdraw their petition. Next steps being determined. (Greg Nizich)

15. **Corn Milling/Ethanol Rule.** Sued by NRDC; suit has been held in abeyance with regular updates provided to the court on the status of our consideration of the reconsideration petitions. A briefing document for Janet McCabe was prepared in the fall of 2014 and forwarded to Janet for consideration (due to timing of Janet's schedule, APMs agreed to seek feedback from Janet without a briefing to continue to move this forward). We expect to start the process to tier the reconsideration rulemaking in the coming months. The rulemaking would grant the reconsideration petition and propose to maintain the 250 tons per year threshold. In addition, we are discussing what other changes we would make in order to put the Agency in a more defensible position—this will likely involve speaking to SIP processing, 302(j), and other issues raised as part of the reconsideration petition. (Dylan Mataway-Novak)

For more information about these rules and the NSR program in general, please visit http://www.epa.gov/nsr.

COMMENTS ON DEPARTMENT OF COMMERCE, *IMPACT OF FEDERAL REGULATIONS ON DOMESTIC MANUFACTURING; NOTICE; REQUEST FOR INFORMATION*

82 FED. REG. 12,786 (MAR. 7, 2017)

Docket ID No. 170302221–7221–01

Submitted March 31, 2017

CHARLES H. KNAUSS
TERESA A. GORMAN
HUNTON & WILLIAMS LLP
2200 PENNSYLVANIA AVENUE, N.W.
WASHINGTON, D.C. 20037
(202) 419-2003
cknauss@hunton.com
COUNSEL TO THE AIR PERMITTING FORUM

SHANNON S. BROOME, EXECUTIVE DIRECTOR
ROBERT M. MOREHOUSE, DIRECTOR
AIR PERMITTING FORUM

The Air Permitting Forum (APF or the Forum) submits these comments in response to the Department of Commerce (the Department) Request for Information (RFI) entitled *Impact of Federal Regulations on Domestic Manufacturing*, 82 Fed. Reg. 12,786 (Mar. 7, 2017).

The Forum is a coalition of companies focused on implementation issues under the Clean Air Act (CAA or the Act), including pre-construction New Source Review (NSR) and Title V permitting, as well as standard-setting under the National Ambient Air Quality Standards (NAAQS), hazardous air pollutant (HAP), and New Source Performance Standards (NSPS) programs. The group was formed in the early 1990s in the wake of enactment of the CAA Amendments of 1990 and the myriad regulations and new requirements that were mandated in that legislation. Forum members, unlike a trade group focused on one particular industry, represent a broad range of U.S. manufacturing sectors and, through their participation in the Forum, have a longstanding record of working with the U.S. Environmental Protection Agency (EPA) to achieve the goals of the CAA in a streamlined and efficient manner. Given the internationally competitive markets in which members operate, the Forum supports cost-effective policies that responsibly promote economic growth and enhance U.S. competitiveness while also supporting CAA and environmental regulatory compliance. This stance is consistent with CAA Section 101(b)(1)'s statement of the purpose of the Act—to protect and enhance the nation's air resources while simultaneously promoting its productive capacity.[1] As a result, the Forum is uniquely qualified to provide input on the Department of Commerce request for information on permit streamlining and reducing regulatory burdens with respect to the CAA.

As industry leaders, Forum members are important drivers of domestic economic growth and job creation. U.S. or overseas manufacturing locations are often determined by manufacturing and distribution costs. Because of this, members seek to streamline the permitting process and to modernize poorly designed and inefficient regulations for domestic manufacturers. Forum members appreciate the Department's and the President's initiative to identify priority actions needed to improve permitting processes and to reduce regulatory burdens more generally.

In response to the President's Memorandum[2] and the RFI, the Forum offers the following comments. Section 1 provides an overview of the permitting challenges experienced by Forum members and the need for reforms which may require both statutory and regulatory changes. It concludes with a "Top 10 List" of recommended principles for reform. Section 2 responds to the specific questions included in the RFI and provides a more detailed assessment of potential opportunities within existing statutory structures, including the CAA, that can be pursued immediately without legislation and without weakening environmental protections. Also attached for your reference are comments that the Forum submitted to EPA in 2005 when the agency

[1] 42 U.S.C. § 7401(b)(1).
[2] White House, Presidential Mem., *Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing* (Jan. 24, 2017).

undertook a year-long comprehensive review of the Title V operating permit program and sought ways to streamline its requirements and implementation.[3] The review was conducted by a small group of Title V experts, the Title V Task Force, representing environmental non-governmental organizations (ENGOs), states, and industrial stakeholders. Both the Forum's current executive director and director were regulated community representatives in that group. We encourage the Administration to review those comments, since many of the recommendations of the Task Force have not been implemented but are just as relevant today as they were 12 years ago.

Section 1: Today's Permitting Requirements are Slowing Economic Growth in Manufacturing

Overview of Permitting Challenges

The Forum offers the following general observations on the burdens created by the current permitting system.

1. *Current permitting requirements impose significant costs on manufacturing, which slow economic growth and meaningful job creation.* U.S. manufacturers face significant challenges in complying with the complex permitting system in the U.S.
    a. Multiple layers of government (federal, state, and local) and agencies have created a permitting system of unreasonable complexity and cost for new construction and improvements of existing plants.
    b. The World Bank lists the U.S. as a country in which it is substantially more difficult to obtain permits for new construction than in many of the U.S.'s major trading partners (*e.g.*, Germany, France, U.K., South Korea, and Taiwan).[4]
    c. Today's permitting requirements also impose time delays on manufacturing that prevent companies from capitalizing on and responding to changing market conditions.

2. *The complexity, cost, and time-consuming nature of current permitting requirements undermine many of their intended environmental benefits.*
    a. The complexity and cost of obtaining permits create an incentive for older plants to keep operating as they are, even though their efficiency could be improved (*e.g.*, by producing more product per unit of time, producing goods with less raw material).
    b. Instead of incentivizing modernization, current permitting requirements discourage capital investment in existing plants if that investment could trigger new permitting requirements, which may be time-consuming and

[3] *See* Comments of the Air Permitting Forum to the Title V Task Force (Mar. 31, 2005), Docket Id. EPA-HQ-OAR-2004-0075-0074, *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2004-0075-0074.

[4] *See* World Bank, *Doing Business — Measuring Business Regulations — Economy Rankings, available at* http://www.doingbusiness.org/rankings (last visited Mar. 30, 2017).

difficult to obtain. Rather than modernizing plants, the system incentivizes companies to continue to operate using less efficient and outdated technology.

3. *Existing permit programs penalize efficiency and utilization improvements at domestic manufacturing plants, allowing our international competition to gain market share at our expense.*
   a. In addition to hindering the construction of <u>new</u> plants, permit programs also hinder equipment upgrades intended to increase plant efficiency and utilization and preserve U.S. jobs at <u>existing</u> plants.
   b. This has the unfortunate outcome of encouraging plants to replace worn-out equipment with the same kind of equipment, when they could be improving both quality and efficiency by installing more efficient, state-of-the-art, and durable replacement parts. It can also encourage plants to accept caps on utilization and production at levels below plant capacity (to avoid permitting burden, delay, and cost), which effectively strands the assets.
   c. As a result, many existing plants forego opportunities to increase efficiency and reduce emissions per unit of output because the air permitting rules dictate that such efficiencies trigger costly permitting requirements.
   d. Ultimately, this places U.S. manufacturers at a competitive disadvantage to other countries that encourage and reward efficiency improvements.

4. *The complex, uncertain, and time-consuming nature of current permitting requirements will also undermine any immediate economic stimulus benefits from infrastructure spending.*
   a. Permitting constraints may delay the actual expenditure of appropriated funds for critical infrastructure projects. While legislators of both parties can agree that some level of federal infrastructure spending is necessary, what is often missed is that permitting delays for federal infrastructure projects may mean that appropriated funds simply cannot be spent on these projects before the appropriation expires.
   b. As a result, permitting constraints remain a major consideration in crafting any stimulus infrastructure spending plan.

5. *The costs and burdens of obtaining a permit are poorly understood and rarely accounted for in estimating the cost of federal regulatory programs, such as in the CAA. This lack of transparency masks the problem such that there has not been an incentive to solve it.* Many costly and time-consuming steps are involved in obtaining an air permit, including:
   a. Applicability determinations—simply determining whether the project will need an air permit. Companies may be forced to spend months and invest substantial funds to make and/or obtain applicability determinations for large, complex projects, incurring substantial delays on just this first step.

b. Identification of covered sources, possible alternative control requirements, including offsetting economic and technical factors.
c. Detailed technical engineering analyses and air quality modeling demonstrations.
d. Legal and technical staff review of applicable regulations and guidance documents.
e. Required demonstrations of compliance with ambient air quality standards "on paper"—such as additional fencing, moving stacks, raising stack heights—which may have no true benefit to air quality for plant modifications and improvements.
f. Contingency planning for alternative paths forward, in light of the uncertainty associated with the ability to obtain permits.

6. *Despite all of these significant steps and costs, the government has a record of ignoring or underestimating the cost and impact of its permitting requirements.*
   a. For example, when Title V was enacted, the administration that authored the bill did not provide a cost estimate, but did suggest that the costs would be minimal. When EPA issued the Title V rules in 1992, it estimated the costs at $526 million annually, costs that have been far exceeded by fees alone.[5]
   b. In addition, Regulatory Impact Analyses (RIAs) of new standards rarely include the effect of new regulations and guidance on the permitting process, and even when they do, they do not capture the costs to the economy of delay and the potential for some projects to not go forward.
   c. The problem is further complicated by the fact that companies rarely track or report the time and resources spent on obtaining permits or on projects that were rejected internally due to the potential expense and delay of permitting.

7. *Obtaining a permit for just one CAA program alone (the NSR program) can require the permittee to review nearly 700 posted guidance documents—a significant burden, and the list of guidance keeps growing every year.*[6] The permitting programs have become elaborate mazes that require hiring law firms and technical staff to navigate at a significant cost.

8. *Preconstruction air permit programs which require a case-by-case review of permit conditions impose a unique and challenging permitting burden on sources and federal/state regulating agencies.*
   a. Due to continuous changes in pollution control technology and its application, case-by-case review of individual permits often translates to changing permit requirements for the same manufacturing technology.

[5] *See* Comments of the Air Permitting Forum to the Title V Task Force, *supra* note 3 at 1-6.
[6] *See* EPA, *New Source Review Policy and Guidance Document Index, available at* https://www.epa.gov/nsr/new-source-review-policy-and-guidance-document-index (last updated Mar. 13, 2017).

b. As a result, there is less certainty that the permit requirements approved within even the same year for a similar source can serve as a guide for an upcoming permit decision.
c. Permit applicants and regulatory agencies must constantly "reinvent the wheel" because the regulations require (or are interpreted as requiring) reviewing and updating previous permit decisions to determine the range of possible outcomes.
d. This level of uncertainty can be challenging for new plants and for modifications at existing facilities because of the potential for the final permitting conditions to impose higher costs than originally expected and potentially undermine the economics of the proposed project.
e. State regulatory agencies are also burdened with conducting extensive, time-consuming reviews that may result in little, if any, incremental benefit, only to be second guessed by EPA after the state determination has been made.

9. *Judicial deference to EPA decisions exacerbates the uncertainty and challenge of obtaining a permit.*
    a. Court deference has given EPA license to reinterpret the regulations or issue new guidance that interprets the regulations in a more stringent way. This means that companies cannot rely on the existing regulation language, preambles, and voluminous guidance that have already been issued to determine if they will need a permit or what the control costs will be if they need one.
    b. This increases overall uncertainty and the potential for new and unexpected permit requirements and rationales.

10. *In states that have obtained approval to run their permit programs, EPA has a history of second-guessing state decisions, introducing delays and risk for companies that work with their states to obtain permits.*
    a. Under the CAA and other environmental statutes, Congress has wisely directed EPA to utilize the expertise and resources of the states to better protect the environment, and for the states to remain our nation's frontline environmental regulators.[7]
    b. Unfortunately, EPA has repeatedly second-guessed the purpose, content, and timing of state permit decisions. This approach conflicts with the "cooperative federalism" intended by Congress. States must be partners and not mere instruments of federal will.

11. *Because of these factors, it is not surprising that obtaining permits has become more challenging for new projects than obtaining capital commitments.*
    a. Traditionally, projects would first obtain financing and then a permit. Now in many cases, project finance is contingent on holding the permit.

[7] *See, e.g.* 42 U.S.C. §§ 7401(b)(3)-(4), (c); 7402(a), (c); 7407(a).

b. This reversal underscores how uncertain and challenging it is to obtain a federal permit. Given the unpredictability of the process, banks now will not extend loans until they know a company has an approved permit.

Principles for Reform

The Forum recommends that the Administration restructure existing permit programs to achieve the same intended benefits and protections at lower costs and with due speed. The Forum provides the following top ten recommendations:

1. Respect decisions made by EPA's state partners as Congress originally intended whenever possible and reduce, if not eliminate, federal second-guessing. Substitute individual permit oversight with federal programmatic overview of state adherence to permitting requirements. States should be evaluated on how their *program* is performing, not micromanaged on each and every permit decision.

2. Increase the transparency of the federal permitting process by tracking and publishing the time from application to issuance. In addition, reduce potential agency "gaming" of NSR permit timing by delaying "completeness determinations," so as to prevent the CAA one–year deadline clock from starting.[8] Provide estimates of the time for regulated entities to prepare applications to help educate the public.

3. Fully analyze and account for the cost of permitting requirements on new construction, competitiveness, and jobs in RIAs for new regulations and in periodic, ongoing reports of the cost of federal regulatory programs. For example, changes in NAAQS can significantly affect companies' ability to obtain permits, the costs of which are never even evaluated.

4. Eliminate or reduce the number of environmental programs that mandate pre-construction authorizations to situations where necessary to protect the public from imminent public health and safety risks. Companies should be able to start construction at their own risk, knowing that additional facility changes may have to be made to comply with any final permit requirements.

5. Eliminate the ability of EPA and stakeholders to modify or re-litigate final construction permit decisions during Title V operating permit revision processes or at renewals. The issuance of a Title V permit should not allow litigants a second opportunity to challenge preconstruction permit decisions.

6. Replace uncertain case-by-case permit review programs with standardized regulatory decisions that are periodically updated through rulemaking after public notice and comment. For instance, the control requirements mandated under the NSPS program provide clear notice to companies of what technology will be

[8] *See* 42 U.S.C. § 7475(c).

required if they build a new process or modify an existing one. In contrast, the NSR permitting program does not provide this certainty, which is one reason decision-making is so protracted and companies are incentivized to limit operations (and productivity) to avoid the program. NSR should provide more certainty as to the controls that will be required. Although the Forum recognizes legislation would be required to substitute NSPS standards for the current case-by-case review under NSR, the Forum recommends administrative changes to the NSR program (listed below) to reduce uncertainty.

7. Incentivize improvements in efficiency rather than creating barriers. It is not enough for EPA's rules to stop discouraging efficiency projects. EPA should be taking affirmative steps to encourage and reward them, as the more efficiently we use our existing resources, the more efficient our overall production in the country will be. This is consistent with the dual purposes of the CAA—to protect the nation's air resources and to *promote the productive capacity* of its population.[9]

8. Consistent with Recommendation 7 above, incentivize efficiency by offering an alternative test to measuring emission increases on a per unit of production basis. Before making a modification at an existing facility, EPA's current regulations require plant operators to project whether a construction project will cause a significant increase in emissions on an annual basis and thus trigger NSR. EPA's current methodology allows for exclusion of emissions increases that are due to factors unrelated to a project, but EPA has narrowly construed this aspect of the calculation and does not provide credit for situations where a production process has become more efficient in producing electricity or manufacturing a product. EPA should seek ways to credit efficiency improvements, for example by focusing on whether the modification at an existing plant reduces emissions per unit of product production, whether it be automobiles, turbines, petrochemicals, or kilowatts.

9. Require EPA to fully implement CAA Section 110(h)(1), which required EPA to assemble and publish all state implementation plans (SIPs).[10] Congress created this requirement because it was virtually impossible to determine which regulations were currently approved as part of the SIP. This lack of transparency serves to delay projects simply because discerning what regulations apply presents its own challenge. The currently approved SIPs should be assembled on one easily-accessible website. This is also important due to the current backlog in state plan approvals, such that the current regulations on the books in the state may differ from what EPA has approved into the SIP as federal law. EPA should also make it a priority to reduce the state plan backlog and limit the number of discretionary requests for additional state plan revisions until the backlog is addressed.

[9] 42 U.S.C. § 7401(b)(1).
[10] 42 U.S.C. § 7410(h)(1).

10. Support legislation to extend the review period for NAAQS and the term of Title V operating permits from five to ten years, and consider the administrative changes recommended below to facilitate permit issuance and renewals.

Section II – Detailed Reform Comments and Response to RFI Questions

Manufacturing Permitting Process

1. How many permits from a federal agency are required to build, expand or operate your manufacturing facilities? Which federal agencies require permits and how long does it take to obtain them?

While numerous federal, state and local permits are required to build a new facility or to modify an existing one, the Forum's comments below focus on EPA's implementation of the CAA's federal air permitting requirements—an issue, as noted above, of significant concern and uncertainty. Obtaining a pre-construction federal air permit for major sources under the CAA is a precondition to building a new manufacturing plant, and to making major modifications at existing units that increase efficiency, utilization and/or production. For air permits, a project typically requires two permits—a construction permit (which may be minor or major) and an operating permit.[11]

The CAA is based on federalism concepts, recognizing that states are in the best position to make determinations about air quality but to do so consistent with national standards. Given the vast array of operations subject to CAA requirements, it makes sense that states are the primary implementers. Thus, under the CAA, states can (and in some cases must) apply for and receive approval for implementing and enforcing clean air programs in their states. States with "delegated" authority implement the federal program, but all must assure compliance with federal standards. With respect to timing, when an NSR permit is required, it can take anywhere from 9 to 36 months from the time an application is submitted for a permit to be issued, not including time needed for possible permit appeals and other delays. This timeframe, however, does <u>not</u> include the many months and potentially years a company may spend in developing the application. As noted above, key steps include determining applicability, the range of alternative control requirements and conducting the necessary technical, air quality modeling and cost demonstrations. In our experience, 9 months is the typical minimum time required for permit issuance once a complete application has been submitted, but the complete permitting process including the pre-permit submission work, can take as long as 3 years, if not longer. Modeling requirements often unnecessarily prolong the permitting process. This issue has been exacerbated by the establishment of stringent

[11] Sometimes three permits are required because both a minor permit and a major permit may be needed if there are pollutants for which the plant is major and others for which it is minor.

short-term (1-hour) NAAQS for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), and the annual average $PM_{2.5}$ NAAQS.

Because of the length of time and uncertainty (including timing and substantive requirements for case-by-case determinations and for permit terms) surrounding the issuance of pre-construction permits, the permit development process often precedes detailed project development. In other words, companies may submit a permit application even before process designs are complete to take into account lead time. This less-defined permit application, where changes to a design may trigger changes to the permit application, further delays permit review and approval. Longer permit approval times also increase the risk that the underlying regulatory requirements reflected in the permit may change or the pending permit may need to be changed to reflect the terms and conditions of other recently approved permitted facilities.

Even for minor NSR permits—*i.e.*, those that do not reach the emission increase levels for major modifications—the timeline for processing can be 6 to 18 months. With the issuance of newer short-term NAAQS, modeling requirements can play a major role in prolonging the permitting process, as states (at EPA's request, in many cases) may require projects to conduct modeling against the 1-hour nitrogen dioxide (NO_2), SO_2 NAAQS, and $PM_{2.5}$ NAAQS. Because EPA regional offices oversee SIP development and implementation, states typically accept EPA "recommendations" that require modeling as part of the permit application process, despite actual measurements of air quality through ambient monitoring networks that indicate attainment with applicable standards. This overly-conservative approach to oversight of project permitting can lead to delays that deter efficiency improvements at existing plants.

2. Do any of the federal permits overlap with (or duplicate) other federal permits or those required by state or local agencies? If the answer is yes, how many permits? From which federal agencies?

Under the CAA, state agencies have primary responsibility for implementing the Act and its requirements, given that they are in the best position to make determinations about allocation of air resources and "headroom" for compliance with the NAAQS. Because of this oversight structure established in the Act, permit overlap between state and federal requirements is not a significant issue for APF members. Rather, a principal challenge is heavy-handedness in federal EPA oversight of CAA programs, which often does not allow states leeway to make independent judgments on Best Available Control Technology (BACT), modeling procedures, and other permitting decisions that should be within their purview under the Act.

3. Briefly describe the most onerous part of your permitting process.

As noted above, Forum members are generally subject to two types of air permits under the CAA—pre-construction permits and operating permits which must be renewed every five years. Of the two, preconstruction permits impose the greater cost and penalty on manufacturing expansion and job creation (though Title V burdens should not be ignored by the government).

Pre-construction permits under the CAA's NSR program require major sources to obtain an approved permit before construction can begin on a new plant or an existing manufacturing plant can be modified (if the modification will result in an emissions increase). In areas of the country that do not meet existing NAAQS—known as nonattainment areas—new and existing sources that trigger NSR must install stringent air pollution controls to achieve the lowest achievable emission rate (LAER) prior to operation and offset any emission increase at a ratio of 1 to 1.1 - 1.5, depending on the status of the nonattainment area. This is known as a nonattainment NSR (NNSR) permit.

In attainment areas, new and existing sources that trigger NSR must also install stringent air pollution controls, known as BACT, prior to operation and demonstrate that the emissions from the construction and operation of the sources will not cause or contribute to a violation of the NAAQS or exceed an air quality increment. This is referred to as a Prevention of Significant Deterioration (PSD) permit.

The process of obtaining a pre-construction permit (whether NNSR or PSD) is time consuming, expensive, and uncertain. Facilities that do not trigger major source permitting are still typically subject to minor source construction permits. Determining whether or not a permit is required is itself a significant source of delay and an obstacle for expanding production in the U.S. Key burdens include:

- *Case-by-Case Determinations*. The determination of LAER or BACT is based on a case-by-case review of the plant and control technologies. As a result, certainty in the permitting process is reduced. Similar sources may end up with significantly different permit requirements. This general lack of predictability undermines project finance and hampers business decision-making.

- *Modeling*. As discussed above, there are numerous issues with modeling, including that states are requiring—often at EPA's request—modeling for minor NSR permits.

- *Disincentives for Modernization and Efficiency Improvements.* While the regulations appropriately provide that routine maintenance, repair, and replacement (RMRR) of existing equipment does not trigger NNSR or PSD, they also provide that *any* physical or operational change that improves efficiency or production can do so. As a result, the regulations bias existing manufacturing plants against equipment upgrades if those upgrades will have the effect of improving a plant's overall efficiency and utilization. This means that the only economical choice is to replace 20-year old parts with parts that are of the same technological sophistication and design as the original parts, rather than with the better and more efficient designs that have been developed in two decades (*e.g.*, as if a person were compelled to purchase a computer today with Y2K technology). There are numerous projects at U.S. manufacturing plants that would improve efficiency or expand production with lower emissions per unit of product produced that may not even be considered due to the burdens of NSR permitting or the inability to obtain a determination from EPA or the state that NSR does not apply, even for already well-controlled plants.

- *Skewed Interpretative Policies.* Existing interpretative policies implementing the CAA's requirements have exacerbated the problem by imposing emission estimation procedures that overstate the likely emissions increase. For example, EPA has recently interpreted its regulations to provide that a facility that projected its emissions from a physical change to be below NSR trigger levels and in fact operated consistent with its projection would still be required to assume for purposes of the permitting process that it will increase emissions, triggering costly permitting requirements. Forcing assumptions that are divorced from reality dramatically increases the number of existing facilities potentially subject to NSR.

- *Project Delays.* As noted above, obtaining a permit is a time-consuming and highly technical process that can take years even before the application permit is submitted. Key steps include project design, permit applicability determinations, identification of potential air pollution controls, detailed technical engineering and cost analyses, air quality modeling and the review of literally hundreds of guidance documents by legal and technical teams. This delay severely hampers the ability of companies to adopt innovations and compete effectively in world markets.

Within the NSR program, it is difficult to pinpoint one particular aspect that is the "most" onerous, given the many complex and resource-intensive requirements. First, the initial determination of whether NNSR or PSD has been triggered may entail numerous hours of engineering and legal evaluation and review. EPA and its state counterparts have generated hundreds of guidance documents interpreting these provisions. Understanding and applying this material—particularly with respect to individual applicability determinations—is estimated by some as the most time-consuming aspect of the permitting process. While one might conclude that a simple solution to this issue is to seek government guidance on the applicability analysis, response time from both the federal EPA and state agencies on such issues is very slow and often leads to overly conservative interpretations (and maximum EPA enforcement discretion). States in particular are hesitant to make definitive determinations, because they want to avoid second-guessing by EPA.[12]

That said, once it has been determined that a permit is required for a project, the application and review processes can be onerous as well, especially for construction projects. These processes are particularly challenging where the relevant state authority is implementing a federal CAA program under EPA delegation (as opposed to where the state is implementing its own approved program) because of the numerous oversight checkpoints involved, an issue most notable in the context of PSD permitting.

[12] *See, e.g., U.S. v. DTE Energy Co.,* 711 F.3d 643, 648 (6th Cir. 2013) (discussing EPA enforcement case concerning power plant's post-project emissions calculations that reflected no significant emissions increase, which were unquestioned by state reviewing authority when submitted).

Because of the complexity of the NSR permitting program, there are several recommendations discussed in the next section which collectively would improve the permitting process.

4. If you could make one change to the federal permitting process applicable to your manufacturing business or facilities, what would it be? How could the permitting process be modified to better suit your needs?

New Source Review

The Forum supports statutory changes to the NSR program given its high cost, questionable net environmental benefits, and its impact in delaying modernization and efficiency improvements at existing manufacturing plants that adhere to the principles outlined above. Short of statutory changes, however, the Forum believes there are several immediate steps the Administration can take to reduce NSR-related permitting burdens without reducing environmental protections by simplifying the federal major NSR permitting process. (40 C.F.R. §§ 51.165; 51.166, 52.21, 52.24, and Part 51, App'x S and W.) Specifically, the Forum proposes the following improvements:

- Respect for EPA's State Partners. Most importantly, as discussed above, is deference to state decisions on applicability and the ability of companies to obtain these decisions, with EPA exercising its oversight role on a programmatic level. In other words, there should be a core presumption that states are making the right decisions, and EPA should spend its resources for oversight looking at whether the decisions of the program as a whole are faithful to the Act.

- Providing Certainty Once the Construction Permit Is Obtained. Because of the interplay between the Title V program and the NSR programs, companies that have obtained construction permits and invested significant funds in constructing a project may face challenges from opponents of the project at the stage where they seek an operating permit. The statute does not contemplate that final construction permit decisions can be challenged at the operating permit stage. It would be helpful for EPA to make clear that challenges to construction of a new project or new plant must be resolved at the construction permit stage and that it will not provide a second bite at the apple once a company has reasonably relied on its permit and built a new project to prevent it from operating or extract additional concessions in order to operate.

- Appropriate Implementation of Demand Growth Exclusion and Causation Requirement. The regulations for both manufacturing and utility plants have always provided that only those emissions that "result" from a project should be counted in determining whether an emissions increase that will trigger PSD or NNSR permitting has occurred. Unfortunately, EPA interpretations of the regulations have undermined this fundamental principle. EPA needs to revisit those determinations and ensure that it faithfully implements the statute.

- Applicability of NSR to Downstream/Upstream Units. When a unit is modified, EPA currently requires, in determining NSR applicability, any emission increases from upstream and downstream units (that were not modified) be considered in the applicability analysis. This discretionary regulatory decision often results in a higher emission calculation than that associated with the unit being modified, thereby assuring that onerous NSR permitting requirements are triggered more frequently. Typically, the included upstream and downstream units (referred to as debottlenecked units) have previously obtained some type of pre-construction permit. Including them in another analysis essentially triggers another round of permitting for those units.

  In light of the current requirements, the Forum recommends that EPA issue a rule which clearly states only emission increases related to the unit being modified should be part of the analysis, not unmodified upstream or downstream units. EPA previously proposed that only emission increases at debottlenecked units "caused" by the physical change or change in the method of operation are to be included in the modification analysis to determine NSR applicability.[13] While the Forum supports this second approach, it suffers from ambiguity over whether emission increases are "caused" by the change. Lack of clarity over issues such as this can delay permits and create significant uncertainty for the company seeking a permit.

- Project Netting and Netting Emission Calculations. The NSR regulations have long allowed facilities to consider emission increases and decreases, from both the current project and other projects which have occurred during a contemporaneous time period, when determining NSR applicability. Prior to the 2002 NSR Reform rules, companies could determine if a project would increase emissions by looking at its effects of increasing and decreasing emissions (*e.g.*, if a project involved shutdown of a unit). Now, EPA provides that any counting of decreases that are projected to occur must take into account all projects in the prior 5 years, a time-consuming and cumbersome process. In the 2006 proposal, EPA proposed to return to the pre-2002 approach, a change that would enable emissions decreases from a project to be included in the calculation of whether a significant emissions increase will result from the project (project netting) in the first place.[14] EPA did not take final action on the proposal in 2009, leaving in place a more cumbersome analysis.[15] EPA should clearly state that emission decreases from a project should be allowed in determining project emissions changes without triggering full 5-year netting of all contemporaneous projects. Returning to the pre-2002 status quo will simplify applicability determinations for companies and reduce permitting burdens on states so they will only need to address those projects that actually cause a significant increase.

[13] EPA, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Debottlenecking, Aggregation, and Project Netting; Proposed rule*, 71 Fed. Reg. 54,235, 54,239 (Sept. 14, 2006).
[14] 71 Fed. Reg. at 54,248-49.
[15] 74 Fed. Reg. at 2376.

On a separate point, EPA has also taken the position that when 5-year netting is conducted, companies must change their analysis of the emissions from previous projects to assume, even though there is no reason to do so (and actual emissions changes from completed projects are known) that emissions in the future will be at potential emission levels. This is the very approach that was rejected in the 2002 NSR Reform Rules and EPA's interpretation should be reversed.

- Aggregation of Projects. In EPA's 2009 final rule,[16] which remains under reconsideration since February 2009,[17] EPA established a rebuttable presumption that projects separated by 3 years or more should are not part of a single project and that there is no presumption for projects that occur within the 3 year time frame to be treated as a single project, as these should be judged on their own facts.[18] Because of the reconsideration process and stay of the 2009 final rule, there is unnecessary confusion regarding what activities must be considered as a single project for purposes of NSR applicability. Aggregating projects that are independent, for the purposes of determining NSR applicability, increases the likelihood of triggering the cumbersome NSR process beyond what was originally intended. It also illegally treats separate changes as a single change in a manner inconsistent with congressional intent when the projects are in fact separate. The Forum agrees that companies should not be able to artificially de-aggregate a project into a single project to circumvent permitting requirements. The 2009 final rule brought needed clarity and simplified administration of the program had it not been put on hold. EPA should remove the stay of the final rule and move to end the reconsideration process.

- Routine Maintenance, Repair, and Replacement Exclusion. EPA has long excluded RMRR activities from NSR applicability because these are not the types of activities Congress contemplated as the "major modifications" which would justify the costly expenditures and lengthy delays associated with a major NSR permit. EPA's actions continue to inappropriately interpret this exclusion narrowly. For example, EPA requires RMRR activities to occur multiple times at a given unit, even though court cases have held that activities routine in the industry should be excluded even if they do not occur frequently at a given unit. Analogizing to car maintenance, the interpretations are akin to treating a transmission replacement as a major modification: a transmission replacement may only occur once over the life of your car, but it is still a replacement that can be expected to occur for car owners generally as a group and one would not consider the replacement of a transmission to create a "new car" for emissions requirements. For major manufacturing plants, RMRR can involve large, high-cost projects necessitating considerable planning. The fact that an activity is costly does not mean that it is not RMRR. EPA should

[16] EPA, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation and Project Netting; Final Rule,* 74 Fed. Reg. 2376 (Jan. 15, 2009).
[17] EPA, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation; Notice of Reconsideration*, 74 Fed. Reg. 7193 (Feb. 13, 2009).
[18] 74 Fed. Reg. at 2377.

issue a new rule to clarify that all routine repairs are excluded even if they are expected to occur only once or twice over the lifetime of a plant.

- Plant-wide Applicability Limits (PAL). EPA's PAL regulations are intended to allow companies to establish a site-wide cap that gives them flexibility to make changes during the term of the PAL without complex new permitting requirements. EPA should also eliminate the ratchet provisions included in the rules and instead provide incentives for companies to accept a ratchet, *e.g.,* allowing them to sell their offset credits to other companies that want to create jobs within the air-shed.

- Assessing Required Control Technology. EPA could substantially improve the determination process for assessing required control technology, specifically the top-down BACT process. While EPA has said that states have flexibility to adopt other approaches, it has expressed its clear preference for states to enforce the top-down process. The top-down BACT process requires permit applicants to identify the most stringent control technology available and to either accept this technology or demonstrate that it is not acceptable based on technical, economic, energy or environmental factors. The permit's final performance-based limits are based on the selected technology. The top-down BACT process is onerous, requiring significant research on recently issued permits, most of which are not readily available. Because technologies change, searches must be updated. The problems with the top-down BACT process have been exacerbated by EPA's greenhouse gas (GHG) BACT guidance document, which interpreted the applicable regulations to require the inclusion of technologies that could not reasonably be applied to a process and to require extensive and costly analysis before such technologies could be rejected. Given that the CAA requires only BACT emission limits, and not the top-down BACT analysis, the Forum recommends that the Administration seek to establish optional presumptive BACT limits through a notice and comment process which could be rebutted by the permittee by proceeding with a case-by-case BACT analysis. Companies seeking permits could then presume with greater confidence the likely outcome of the permitting process. Moreover, state regulators would benefit from reduced second-guessing from federal officials. At a minimum, EPA should issue guidance clarifying that states with SIP approved programs have the authority to prepare and determine BACT based emission limits in accordance with their program.

- Modeling. In conducting an analysis for the PSD program, facilities must use EPA-approved models to demonstrate that a project will not cause a violation of a NAAQS standard. The models' overly conservative algorithms and assumptions, however, can create a modeling result that rarely represents and often significantly overestimates monitored concentrations around the facility. Reliance on modeling that over-predicts ambient concentrations can result in additional unwarranted costs by causing facilities to install beyond-BACT pollution control equipment, even though the assumptions used in the models and the predicted concentrations are not representative of real-world conditions.

The NAAQS for SO_2, NO_2, and annual $PM_{2.5}$ have created urgency in addressing this modeling conservatism due to the stringency of these new standards. Modeling demonstrations for the NO_2 and SO_2 1-hour and $PM_{2.5}$ standards have proven to be extremely difficult for many sources, especially during transient operations such as startup and shutdown. The Forum recommends that EPA review and reconsider key modeling assumptions that do not represent real-world conditions. This includes more realistic modeling scenarios based on actual, variable emissions.[19] It also means identifying true background levels and including reasonable assumptions regarding neighboring emissions. Because of the stringency of these standards, EPA has allowed some proposals to use monitored data along with modeled data. EPA should be encouraged to allow monitored data along with modeled data when it is available and provide greater flexibility in modeling intermittent operations.

- Significant Emission Rate (SER) for GHGs. In October 2016, EPA proposed a rule to establish a significant emission rate for GHGs of 75,000 tons of carbon dioxide equivalent (CO_2e), or potentially less based on the proposal.[20] GHGs are emitted in quantities significantly higher than those for traditional criteria pollutants, which drives the need for a higher SER to avoid tens of thousands of potentially impacted sources. The Forum submitted comments on the proposed rule recommending that EPA finalize a SER value much higher than 75,000 tons per year based on the number of sources covered and the marginal effect the permitting requirements would have.[21] The Forum continues to support this change. Permitting requirements should be applied only to sources where they will yield a meaningful benefit.

Title V Operating Permits

Title V of the CAA requires all major sources and a limited number of smaller sources to obtain and renew operating permits to continue to operate. The permit is a legally-enforceable document intended to facilitate compliance by listing applicable air pollution control requirements. The Title V operating permit, however, was not intended to create new substantive requirements or increase the stringency of existing control requirements.

Unfortunately, obtaining, maintaining, and renewing Title V permits has become costly and controversial. With thousands of plants subject to the program, the cost of the program today is far more than was ever anticipated and no one has asked the question whether the benefits being obtained are worth this investment. While the

[19] For example, many sources run intermittently, such that the worst case assumptions in the models grossly overstate impacts.

[20] EPA, *Revisions to Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program; Proposed Rule*, 81 Fed. Reg. 68,110 (Oct. 3, 2016).

[21] Comments of the APF in response to EPA proposed Revisions to the PSD and Title V GHG Permitting Regulations and Establishment of a SER Rate for GHG Emissions Under the PSD Program, (Dec. 16, 2016) Docket Id. EPA-HQ-OAR-2015-0355-0091, *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0355-0091.

Forum is not advocating for repeal of Title V, we believe that given the enormous costs of the program it is incumbent on the government to take whatever steps it can to streamline permitting and minimize costs. This is even more important given that the level of costs were never predicted by the Administration when it authored the bill and were never disclosed to Congress. These core issues are exacerbated by the fact that members of the public can view modification to incorporate new construction permit requirements or renewal of a Title V permit as an opportunity to reopen permit terms that have already been decided and on which companies have relied for planning purposes. Indeed, ENGO groups that unsuccessfully challenged the outcome of a major or minor NSR permit are now challenging the Title V permits on the same grounds that have already been adjudicated. Moreover, Title V petitions often sit in a long queue at EPA, and then can end up back in court—duplicating costs for industry to defend its expansive and long-evaluated permits.

While changes to the NSR permitting program remain a higher priority for Forum members, APF also recommends improved implementation of the Title V operating permit program to help reduce costs and facilitate the permitting process. Specifically, the Forum recommends that EPA:

- Implement recommendations of the Title V Task Force related to streamlined compliance certifications, facilitating faster processing of permit modifications, and reducing fees.
- Actively review the existing program to identify opportunities to reduce costs, recognizing that the Title V program was not intended to create new applicable emission standards or requirements.
- Ensure that the Title V fees that are collected are being used exclusively for the Title V operating permit program, minimize transaction costs, and encourage states to innovate with fees to fund expediting permits (which applies to both operating and construction permits).
- Minimize the potential for stakeholders to use the Title V operating program as an opportunity to seek additional review and litigation over issues that should have been raised and decided in rulemakings over the underlying applicability requirements. For instance, EPA should forcefully deny Title V petitions on issues already ruled on in the underlying NSR permit.
- Although this would require a statutory change, it makes sense to lengthen the permit term from five to ten years to reduce burdens on states since modifications are required for significant changes anyway. Until a statutory change is made, EPA should look for opportunities to streamline the renewal process to reduce burdens.

5. Are there federal, state, or local agencies that you have worked with on permitting whose practices should be widely implemented? What is it you like about those practices?

A number of states (*e.g.*, South Carolina, Georgia, Louisiana, Texas) have implemented "expedited" permitting processes for issuance of permits in a timely manner. This has resulted in improved processes and reduced uncertainty with obtaining permits. These states allow companies that have a need for an expedited permit to pay additional fees to fund overtime or allocate resources (*e.g.*, expedited publication of public notices) to move a permit through the required processes faster. In addition, the fees help offset state costs of implementing permitting and incentivize states to be responsive stewards of economic growth. In Indiana, there is a fast-track permitting process that allows for construction to begin in 21 days with an initial public notice and then a subsequent notice while the company begins construction at its own risk. EPA approved Indiana's program and it has operated well. EPA should encourage these types of programs in other states and move quickly to approve them in other states. Ohio EPA piloted a program in which it took normally sequential steps in permit processing and executed them in parallel, significantly reducing overall permit processing time. EPA should also seek and embrace these and other innovative approaches to permitting, recognizing the true costs of the preconstruction and operating permitting programs.[22] Examples of other approaches that could be employed include: the Texas Commission on Environmental Quality's tiered BACT approach, expedited permitting programs in Texas and Louisiana (which are similar to South Carolina, Georgia, and Indiana), imposition of statutory timelines to process permits (which are seen in Indiana and Pennsylvania), permits by rule and general permits that companies can opt into for standard pieces of equipment, and the like.

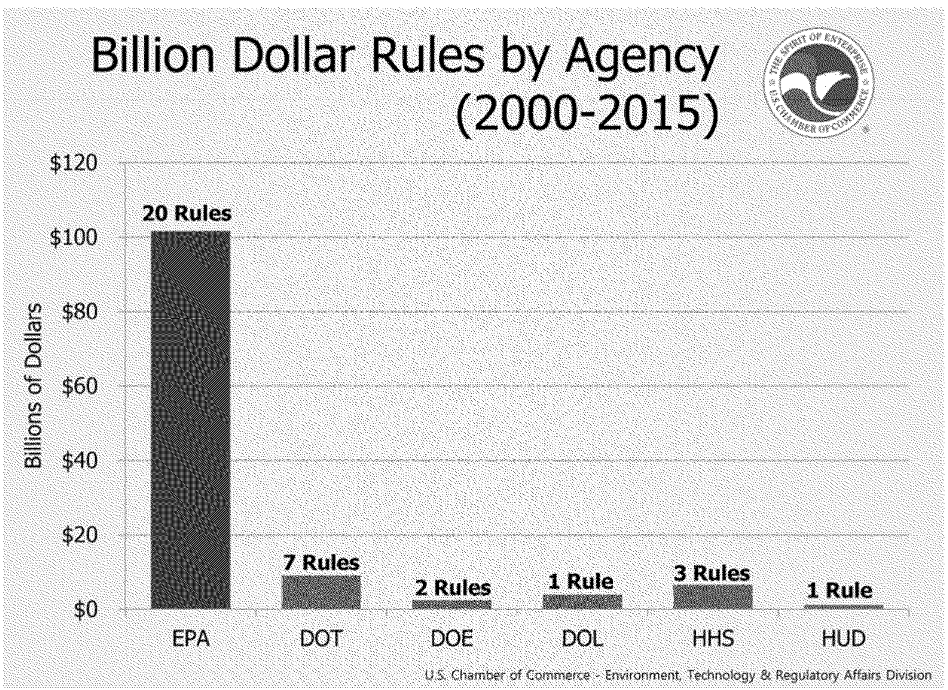
[22] The concepts embodied in EPA's 2009 "Flexible Air Permitting Rule" provides a valuable starting point for this effort. The Forum specifically recommends that EPA promote and directly facilitate issuance of innovative state/regional air quality permits that include and allow for "advance-approve" changes at manufacturing facilities. *See* EPA, *Operating Permit Programs; Flexible Air Permitting Rule; Final Rule*, 74 Fed. Reg. 51,418 (Oct. 6, 2009). EPA could use this opportunity to broaden the scope of facility changes that qualify for advance-approval. The resulting "advance-approved" permits could be used to streamline multiple redundant or conflicting applicable requirements into a single set of permit requirements, and ensure that innovative air permits require no more time to issue than "traditional" air permits.

Regulatory Burden/Compliance

The following comments respond to the RFI's questions concerning regulatory burden and compliance.

1. **Please list the top four regulations that you believe are most burdensome for your manufacturing business. Please identify the agency that issues each one. Specific citation of codes from the Code of Federal Regulations would be appreciated.**

Although there are many federal regulatory programs impacting manufacturing, EPA regulations dominate in cost and impact. As shown in the chart below, the number of billion-dollar rules issued by EPA far exceeds any other federal agency. The Forum hopes that the Department of Commerce will appropriately weigh EPA's disproportionate role and impact in prioritizing actions for reform.



Source[23]

[23] U.S. Chamber of Commerce, *The Most Costly Federal Rules: Billion Dollar Regulations*, *available at* https://www.uschamber.com/the-most-costly-federal-rules-billion-dollar-regulations (last visited Mar. 30, 2017).

Within the environmental area, Forum member facilities are subject to numerous regulatory requirements, many of which pose permitting and compliance burdens.[24] We offer the following four priorities for the Administration to consider: NAAQS standards/implementation; Section 112 policies and regulations for HAPs and its Risk Management Plan (RMP) regulations; standard-setting for malfunctions; and ozone-depleting substance regulatory revisions.

a. National Ambient Air Quality Standards

NAAQS regulations continue to represent some of the most costly federal regulations issued by EPA. The establishment of new ambient air quality standards unfurl a series of stationary and mobile source controls across the country to help bring areas into attainment. In areas classified as a nonattainment, the designation and effective impact of controls can hinder business development and job creation because they create complex regulatory environments with overlapping requirements. Published reports from the National Bureau of Economic Research confirm the severity of these impacts. Between 1972 and 1987, researchers have concluded, based on a review of more than a million manufacturing plant observations, that nonattainment counties (relative to attainment ones) lost approximately 590,000 jobs, $37 billion in capital stock, and $75 billion (in 1987 dollars) of output in pollution-intensive industries.[25]

The underlying statutory requirements do not allow the consideration of cost in setting a new standard. As a result, as the NAAQS have grown increasingly more stringent, health and environmental benefits have reached a point of diminishing returns while compliance costs have escalated. In order to estimate the cost of compliance with recent ozone standards, EPA relied on speculative estimates of the cost of unknown controls and new technologies that have yet to be developed to envision a compliance scenario. EPA's most recent ozone standards have become so stringent that background concentrations approach the level of the standard in some locations of the country, such as in the western states, meaning that they may not be able to demonstrate attainment and putting them at risk of sanctions such as loss of federal highway funds.

In addition to imposing high compliance costs on the country, the stringent NAAQS bring additional costs and delays to permitting decisions. As noted above, the overall stringency of NSR requirements differ depending on whether an area is classified as in attainment or non-attainment of a NAAQS. Tighter standards force more areas into nonattainment, resulting in more expensive air pollution control costs under the NSR preconstruction permitting requirements. But this is only half the story. For PSD permits, the tighter standards significantly increase the technical challenge of

[24] Because the Forum's comments are limited to CAA-related regulatory programs, the Forum reserves comment on whether there are individual regulations outside the purview of EPA that may be more burdensome on individual manufacturing facilities than the EPA regulations listed below.
[25] Greenstone, Michael, "The Impacts of Environmental Regulations on Industrial Activity: Evidence from the 1970 & 1977 Clean Air Act Amendments and the Census of Manufactures," National Bureau of Economic Research, Working Paper No. 8484, (Sept. 2001).

demonstrating that the new plant or modification will not contribute to a potential NAAQS violation—an air quality demonstration that can become very difficult as standards approach background concentrations. Similarly, the adoption of short-term NAAQS for NO_2, SO_2, and $PM_{2.5}$ (*i.e.* 1-hour, 24-hour) has also made it challenging for sources to make the required modeling demonstration.

All of these factors make it more difficult and uncertain to expand manufacturing operations in the U.S. At a minimum, they will delay construction and in some cases may serve to prevent projects from going forward. These permitting complexities are compounded by the fact that it takes years after a NAAQS is revised for EPA to issue what are called "implementation rules"—the rules of the road for states and companies that must comply with the standards[26]—and when they are issued, they do not do enough to ease the transition. As a result, companies face uncertainty about what the requirements will be for their plants years after the standards are issued. This includes questions surrounding statutory interpretations on reasonably available control technology, offsets (*e.g.* substitutions, ratios), and attainment obligations. The uncertainty undermines the ability of manufacturers to plan projects with a certain timeline and cost expectation, creating incentives for projects to be done at other locations in and outside the U.S. where these uncertainties do not exist. Conversely, the requirements in attainment areas apply immediately after the revised NAAQS is final even though there is a lack of tools to implement it. The NAAQS process does anything but make regulation regular for those who must comply.

In light of these many factors, the Forum supports the following statutory and regulatory changes to the NAAQS program.

- Although this would require a statutory change, the required five-year statutory review of each NAAQS should be lengthened to ten years to more appropriately reflect the scientific and technical challenge of assessing and revising the standard and to allow time for science to advance between reviews. This will also increase the likelihood that areas can make meaningful progress toward meeting a standard before it is revised.

- The Administrator should consider a standard's attainability in establishing a NAAQS. Failure to consider attainability increases the likelihood that EPA will establish standards that regions of the country cannot realistically meet.

- EPA should establish a clear implementation transition policy of grandfathering all new sources for purposes of PSD permitting that have submitted a PSD application prior to the finalization of a new NAAQS, particularly since the time for processing applications once submitted is out of the control of the applicant. This would prevent sources from having to redo air quality modeling and related technical analysis to

[26] For example, significance levels are critical to planning projects, and companies planning projects that may be a few years out will not know the relevant levels against which to determine permitting requirements.

address the recently finalized standard. It would also prevent companies from having to wait for new modeling or measurement techniques to make updated air quality demonstrations. Without clear transition rules, including the grandfathering in of PSD permit applications, construction at new and existing sources subject to PSD will be unnecessarily delayed across the country.

- EPA should also adopt appropriate grandfathering rules for sources in newly designated nonattainment areas that are being permitted at the time a NAAQS may transition to a more stringent level. Because of the delays in obtaining NSR permits and the five-year NAAQS review cycle, companies can find themselves facing new and unanticipated requirements when EPA revises the standard. This situation is critical because EPA has persistently determined that revised NAAQS become effective for permitting sources immediately upon the effective date, despite the fact that state regulatory agencies have up to two years to determine attainment relative to the new standard and several years longer to devise control strategies.

- EPA should also establish clear standards for conducting NAAQS scientific reviews, including clear criteria for assessing and ranking health effects studies, a transparent system for objectively weighing the evidence, and a balanced and open peer review process that allows for a meaningful comment process.

- Despite clear statutory language under CAA Section 109(d) requiring EPA's NAAQS scientific advisory committee to assess the public health, welfare, social, economic, or energy effects which may result from various strategies for attainment and maintenance of the NAAQS,[27] EPA has failed to request the analysis and to provide the advisory committee with sufficient resources to conduct the required analysis. EPA should take immediate steps to assure that the required analysis is conducted for all future NAAQS standards in a timely manner. This is important because there has been no clear review and understanding of the potential for adverse consequences from the attainment process, and if there had been, Congress and EPA could have taken concrete steps to ensure welfare, social, economic, and energy benefits.

- With respect to air quality demonstration modeling, EPA should:

    - Eliminate numerous conservative assumptions that tend to over-predict the potential impacts of a source's emission changes relative to the NAAQS. This is confirmed by ambient monitoring data collected near manufacturing sites that show concentrations that are well below the standards even when the required modeling results show "on-paper" exceedances that would prevent a source from being permitted. It is important to note that the NAAQS themselves are already based on conservative assumptions including a "margin of safety" for sensitive individuals. Over-predicting the contribution of emissions to ambient concentrations compounds that conservativism,

[27] 42 U.S.C. § 7409(d).

especially when considering the fact that new standards are being set close to background levels (*e.g.* ozone). Given the increasing technical challenges posed by the stringent NAAQS and the conservative modeling assumptions, many permit applicants may simply decide not to submit a permit application for projects that will improve productivity or bring new jobs.

- Allow the option for the company to proceed with permitting based on collection of monitoring data after construction of the project rather than relying on overly conservative modeling assumptions. EPA has implemented this approach in some permits already when it appeared that the model was over-predicting the impacts that would occur in practice. This type of approach includes reopeners in the permit to address actual exceedances.

- Empower states to make modeling decisions. EPA headquarters staff should not have to approve all variances from permit dispersion modeling procedures. This review delays the approval of any project, since most permit applications are reviewed at the state level. Federal modeling guidelines at 40 C.F.R. Part 51 – Appendix W explicitly assign review and approval duties to the "appropriate reviewing authority," which is primarily the state/local regulatory permitting agencies, occasionally in limited circumstances after consultation with the EPA Regional Office. Given the experience of state permit engineers, states should be empowered to approve changes to the modeling procedures and make reasonable site-specific determinations based on sound science and reasonable judgment of facts relevant to each application. EPA, and the public, always have the opportunity to review changes during the public and EPA permit review period.

b. Section 112: Hazardous Air Pollutants and Risk Management Plan Regulation Revisions

The CAA Section 112 program covers the regulation of hazardous air pollutants (a defined list) for various source categories.[28] Initially, these National Emission Standards for Hazardous Air Pollutants (NESHAPs) were established based on a review of currently employed air pollution control technology applied to existing and new sources (referred to as Maximum Achievable Control Technology, or MACT). Then, after eight years, the statute requires EPA to conduct residual risk and technology reviews.[29] EPA assesses the risk remaining after application of MACT controls and determines if it is acceptable. If not acceptable, further controls must be applied.[30] EPA is also required to evaluate if advances in control technologies have occurred since the MACT and to determine if their application to the source category is appropriate.[31] Opportunities to improve Section 112 implementation include:

[28] 42 U.S.C. § 7412.
[29] 42 U.S.C. §§ 7412(d)(2), (f)(2).
[30] 42 U.S.C. § 7412(f)(2).
[31] 42 U.S.C. § 7412(d)(2).

- Repeal Once-in-Always-in-Policy. EPA established a policy that once a source is subject to a MACT standard (major source), the regulatory obligations associated with the applicable MACT standard remain even if the facility undertakes pollution prevention or installs control devices to reduce emissions below the major source applicability thresholds. This policy is not mandated by the statute and creates a significant disincentive for companies to reduce emissions; it also imposes costly monitoring requirements when none are needed. Moreover, because "major sources" must obtain Title V permits, this policy means that sources are prevented from reducing emissions to avoid Title V permitting. EPA had proposed to eliminate the policy,[32] but an appropriations bill blocked finalization of the rule prior to the Obama Administration taking office. The proposal was never withdrawn and EPA remains free to take final action on that proposal.

- Residual Risk Review Should Inform Technology Review. EPA should interpret the statute to conclude that if a risk review shows the existing standard is protective of public health with an ample margin of safety, no further technology reviews are required. Requiring added controls under a technology review when risk is demonstrated to be acceptable generates unnecessary costs.

- Pollutant-by-Pollutant Standard Setting Process. EPA has established Section 112 limits pollutant-by-pollutant in some MACT standards, which can create an unachievable standard that no one source can meet. EPA should modify its policy to ensure standards are achievable and establish achievability by considering all pollutants in setting standards for source categories.

- RMP Rule Revisions. The Forum refers the Agency to the Petition for Reconsideration and Stay submitted by the Chemical Safety Advocacy Group on March 13, 2017.[33] The January 13, 2017 RMP rule revisions are inappropriate and should be substantially revised.

c. Standard-Setting for Malfunctions.

In the past few years, EPA has taken the position that emission standards applicable to normal operations must also apply during malfunction periods. It is widely recognized that even the best designed piece of equipment can break down, even if it is well-maintained. As far back as the 1970s, the courts have told EPA that it needed to

[32] EPA, *National Emission Standards for Hazardous Air Pollutants: General Provisions; Proposed Rule*, 72 Fed. Reg. 69, 70 (Jan. 3, 2007).
[33] Chemical Safety Advocacy Group, Pet. for Reconsideration and Stay of EPA's *Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act; Final Rule*, 82 Fed. Reg. 4594 (Jan. 13, 2017) dated Mar. 13, 2017.

take these situations into account and not force companies into "noncompliance" when unpreventable malfunctions occur.[34]

While recent court decisions indicate that an outright exemption under CAA Section 112 is not permitted for startup, shutdown, and malfunction situations,[35] EPA's response has not always been appropriate. Rather than systematically develop a "work practice" standards for these situations, EPA has often concluded that it would simply apply the standards developed based on data for normal operating modes during these unpredictable operating modes. When defaulting to this position, EPA has not diligently sought alternatives. Such an approach penalizes companies that do the right thing—they install the controls; they maintain their equipment; they operate it well. Companies should not be at risk of enforcement and citizen suits in these situations.

Unfortunately, EPA has incorrectly applied this same approach to the NSPS program and SIPs for NAAQS. EPA is now requiring states to remove affirmative defenses for malfunctions from emissions standards included in these plans or make them state only. Instead of inappropriately applying the MACT decision to SIPs, EPA should address the problem by reinstating its previous guidance on affirmative defense.

The Administration can take steps to immediately address these problems by establishing work practice standards for Section 112 standards that can apply during malfunction periods and by reinstating previous guidance on affirmative defense for SIPs. Such an approach will ensure responsible operation of plants that minimizes emissions, while not creating unreasonable and unattainable requirements for companies.

d. Ozone-Depleting Substances

EPA recently expanded the detailed refrigerant management requirements currently applicable to Class I and II refrigerants to include substitutes.[36] The rule is currently being challenged in the U.S. Court of Appeals for the D.C. Circuit.[37] CAA Section 608 requirements were established to regulate ozone depleting substances, but the expansion to substitutes means that EPA is applying Section 608 to chemicals that may not be ozone depleting. EPA is transforming this provision beyond ozone-layer-protection to achieve other policy goals not intended by Congress to be addressed under this provision.

[34] *See, e.g.*, *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (a "standard . . . must be achievable" under section 111); *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433 (D.C. Cir. 1980) (EPA bears the burden of explaining "how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated").
[35] *See Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008).
[36] *See* EPA, *Protection of Stratospheric Ozone: Update to the Refrigerant Management Requirements Under the Clean Air Act; Final Rule,* 81 Fed. Reg. 82,272 (Nov. 18, 2016) (Final Rule).
[37] *Nat' Envtl. Dev. Ass'n Clean Air Project v. EPA*, No. 17-1016 (D.C. Cir. filed Jan. 17, 2017).

2. How could regulatory compliance be simplified within your industry or sector?

The Forum offers the following additional suggestions to simplify CAA permitting and compliance for manufacturing facilities.

- Regulatory interpretations. Often, after a rule has been finalized, or even years later, questions arise with regards to rule applicability or a compliance requirement. The EPA individuals most familiar with the rule background and issues discussed during regulatory development are those in the Office of Air Quality and Planning Standards (OAQPS) (or outside of the air program in the substantive divisions). These substantive experts are primarily responsible for standard-setting. Once a rule is finalized, however, interpretations of those regulations become the responsibility of the enforcement office (OECA). In most cases, the OECA personnel addressing the interpretation question are less familiar with the rule and in our experience have at times imposed interpretations inconsistent with the intent of the rule. The responsibility for responding to regulatory interpretations should be assigned to the division or group responsible for the original rule development.

- Reporting Requirements. Harmonizing federal and state reporting requirements would help to simplify facilities' reporting obligations. Currently, EPA requires electronic reporting of facility information, whereas states require hard copy submittals. Aligning these requirements would allow facilities to fulfill their reporting obligations in a uniform and consistent manner.

* * * * *

The Forum appreciates the opportunity to comment on the Notice. Please contact Chuck Knauss at cknauss@hunton.com, Shannon Broome at sbroome@hunton.com, or Bob Morehouse at rmorehouse@hunton.com with any questions regarding these comments.

No. 17-170

In the Supreme Court of the United States

DTE ENERGY COMPANY, ET AL., PETITIONERS

v.

UNITED STATES OF AMERICA, ET AL.

ON PETITION FOR A WRIT OF CERTIORARI
TO THE UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

BRIEF FOR THE UNITED STATES IN OPPOSITION

NOEL J. FRANCISCO
Solicitor General
Counsel of Record
JEFFREY H. WOOD
Acting Assistant Attorney General
ROBERT J. LUNDMAN
THOMAS A. BENSON
Attorneys

Department of Justice
Washington, D.C. 20530-0001
SupremeCtBriefs@usdoj.gov
(202) 514-2217

QUESTION PRESENTED

Whether an enforcement action alleging that projections of emissions increases required the operator of a pollution source to obtain a permit under the Clean Air Act, 42 U.S.C. 7401 *et seq.*, is categorically barred when the operator has completed construction without a permit and emissions have not increased thereafter.

TABLE OF CONTENTS

Page

Opinions below 1
Jurisdiction 1
Statement....................2
Argument....................8
Conclusion....................17

TABLE OF AUTHORITIES

Cases:

Adickes v. *S. H. Kress & Co.*, 398 U.S. 144 (1970) 15
Alaska Dep't of Envtl. Conservation v. *EPA*, 540 U.S. 461 (2004) 9, 10
CleanCOALition v. *TXU Power,* 536 F.3d 469 (5th Cir.), cert. denied, 555 U.S. 1049 (2008) 11
Environmental Def. v. *Duke Energy Corp.*, 549 U.S. 561 (2007) 2, 3, 9, 15
Good Samaritan Hosp. v. *Shalala*, 508 U.S. 402 (1993) 15
Hamilton-Brown Shoe Co. v. *Wolf Bros. & Co.*, 240 U.S. 251 (1916) 16
National Parks & Conservation Ass'n v. *Tennessee Valley Auth.*, 502 F.3d 1316 (11th Cir. 2007), cert. denied, 554 U.S. 917 (2008).................... 11
New York v. *U.S. EPA*, 413 F.3d 3 (D.C. Cir. 2005).....12, 16
Sierra Club v. *Otter Tail Power Co.*, 615 F.3d 1008 (8th Cir. 2010).................... 11
Texas v. *EPA*, 726 F.3d 180 (D.C. Cir. 2013)....................11
United States v. *Alabama Power Co.*, 730 F.3d 1278 (11th Cir. 2013)....................11
United States v. *Cinergy Corp.*, 623 F.3d 455 (7th Cir. 2010)....................11

Cases—Continued: Page

United States v. *EME Homer City Generation, L.P.*, 727 F.3d 274 (3d Cir. 2013) 11

United States v. *Midwest Generation, LLC*, 720 F.3d 644 (7th Cir. 2013) 10

Virginia Military Inst. v. *United States*, 508 U.S. 946 (1993) 16

Wisconsin Elec. Power Co. v. *Reilly*, 893 F.2d 901 (7th Cir. 1990) 12, 16

Statutes, regulations, and rule:

Clean Air Act, 42 U.S.C. 7401 *et seq.* 2
- 42 U.S.C. 7401(b)(1) 2
- 42 U.S.C. 7411(a)(4) 3
- 42 U.S.C. 7413 13
- 42 U.S.C. 7475(a) 2, 10
- 42 U.S.C. 7475(a)(2) 2
- 42 U.S.C. 7475(a)(3) 2
- 42 U.S.C. 7475(a)(4) 2
- 42 U.S.C. 7475(a)(6) 3
- 42 U.S.C. 7477 13
- 42 U.S.C. 7479(2)(C) 3

Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685 2

Dictionary Act, 1 U.S.C. 1 13

Exec. Order No. 13,783, 82 Fed. Reg. 16,093 (Mar. 31, 2017) 9

40 C.F.R.:
- Section 52.21(a)(2)(iii) 3, 11
- Section 52.21(a)(2)(iv) 4
- Section 52.21(a)(2)(iv)(*a*) 13
- Section 52.21(a)(2)(iv)(*b*) 14

Regulations and rule—Continued: Page

Section 52.21(a)(2)(iv)(*c*) 4, 11, 13
Section 52.21(b)(2)(i) 3
Section 52.21(b)(3) 13
Section 52.21(b)(3)(i) 4
Section 52.21(b)(23) 5
Section 52.21(b)(41)(ii)(*a*) 8
Section 52.21(b)(41)(ii)(*c*) 4
Section 52.21(r)(1) 11, 14
Fed. R. Civ. P. 54(b) 7

Miscellaneous:

EPA, *Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783* (Oct. 25, 2017), https://www.epa.gov/sites/production/files/2017-10/documents/eo-13783-final-report-10-25-2017.pdf 9
45 Fed. Reg. 52,676 (Aug. 7, 1980) 4
68 Fed. Reg. 61,248 (Oct. 27, 2003) 4

In the Supreme Court of the United States

No. 17-170

DTE ENERGY COMPANY, ET AL., PETITIONERS

v.

UNITED STATES OF AMERICA, ET AL.

ON PETITION FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE SIXTH CIRCUIT

BRIEF FOR THE UNITED STATES IN OPPOSITION

OPINIONS BELOW

The opinion of the court of appeals (Pet. App. 1a-47a) is reported at 845 F.3d 735. The opinion of the district court (Pet. App. 57a-61a) is not reported but is available at 2014 WL 12601008. A prior opinion of the court of appeals (Pet. App. 62a-85a) is reported at 711 F.3d 643. A prior opinion of the district court (Pet. App. 86a-99a) is not reported but is available at 2011 WL 3706585.

JURISDICTION

The judgment of the court of appeals was entered on January 10, 2017. A petition for rehearing was denied on May 1, 2017 (Pet. App. 48a-49a). The petition for a writ of certiorari was filed on July 31, 2017 (Monday). The jurisdiction of this Court is invoked under 28 U.S.C. 1254(1).

STATEMENT

1. a. The Clean Air Act (CAA or Act), 42 U.S.C. 7401 *et seq.*, was enacted "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42 U.S.C. 7401(b)(1). The Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685, amended the Act to require, *inter alia*, that a permit must be obtained "before a 'major emitting facility' could be 'constructed'" in particular areas. *Environmental Def.* v. *Duke Energy Corp.*, 549 U.S. 561, 568 (2007) (quoting 42 U.S.C. 7475(a)).[1] As currently codified, a section entitled "Preconstruction requirements" prescribes a permitting process wherein a source must, *inter alia*, (i) undergo a review (including a public hearing) that addresses factors such as "the air quality impact of such source" and "alternatives thereto," 42 U.S.C. 7475(a)(2); (ii) demonstrate that its emissions "will not cause, or contribute to, air pollution in excess of" various standards, 42 U.S.C. 7475(a)(3); (iii) apply the "best available control technology" to limit air pollutants from the "proposed facility," 42 U.S.C. 7475(a)(4); and (iv) un-

[1] The program described in *Duke Energy* is one of two "generally parallel" programs—"Nonattainment New Source Review" and "Prevention of Significant Deterioration"—that apply to particular areas by pollutant, based on whether those areas are designated as not attaining national ambient air quality standards established by the EPA for the pollutant. Pet. App. 64a n.1. The facilities at issue here are located in an area that is subject to one program for some pollutants and the other program for other pollutants. *Ibid.* Because the differences between the programs "do not affect this case," *ibid.*, this brief will focus on the program described in *Duke Energy*.

dertake "an analysis of any air quality impacts projected for the area as a result of growth associated with such facility," 42 U.S.C. 7475(a)(6).

Shortly after the 1977 amendments were adopted, Congress enacted a technical amendment providing that "[t]he term 'construction' when used in connection with any source or facility, includes the modification (as defined in [42 U.S.C. 7411(a)(4)]) of any source or facility." *Duke Energy Corp.*, 549 U.S. at 568 (citation omitted); see 42 U.S.C. 7479(2)(C). As a result of that provision, "the 'construction' requiring a * * * permit under the statute was made to include (though it was not limited to) a 'modification,' as defined in [the relevant] provisions." *Duke Energy Corp.*, 549 U.S. at 568. Those provisions define "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. 7411(a)(4).

b. Regulations promulgated by the Environmental Protection Agency (EPA) provide that "[n]o new major stationary source or major modification * * * shall begin actual construction without a permit." 40 C.F.R. 52.21(a)(2)(iii). The regulations define the term "[m]ajor modification" to include "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase * * * of a [relevant] regulated * * * pollutant * * * ; and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. 52.21(b)(2)(i) (emphasis omitted).

As the court of appeals explained in its initial opinion in this case, "to determine whether a proposed change would cause a significant emissions increase, and thus require a permit, an operator must project post-change emissions." Pet. App. 66a. The regulations state that "[a] significant emissions increase * * * is projected to occur if the sum of the difference between the projected actual emissions" and past or "baseline actual emissions" exceeds a regulatory threshold. 40 C.F.R. 52.21(a)(2)(iv)(*c*); see 40 C.F.R. 52.21(b)(3)(i) (defining "[n]et emissions increase" in part by reference to 40 C.F.R. 52.21(a)(2)(iv)) (emphasis omitted). To isolate the increases attributable to the new construction (*i.e.*, to distinguish those increases from increases attributable to other factors), certain projected emissions increases may be excluded from the calculation under what is known as the "demand growth" exclusion. 40 C.F.R. 52.21(b)(41)(ii)(*c*); see Pet. App. 66a-67a, 69a.

Although the regulations include certain reporting and recordkeeping requirements, they do not require a source that concludes that its projected emissions will fall below the regulatory threshold for a permit to seek verification of that conclusion from the EPA before commencing construction. See Pet. App. 67a. The EPA has historically interpreted its program to mean that an operator is subject to an enforcement action if it proceeds based on a deficient analysis. See 45 Fed. Reg. 52,676, 52,725 (Aug. 7, 1980) ("Any source which improperly avoids review and commences construction will be considered in violation of the applicable" regulatory scheme "and will be retroactively reviewed under the applicable * * * regulation."); see also 68 Fed. Reg. 61,248, 61,250 (Oct. 27, 2003) (noting that a source may seek an official determination of whether a particular permit exception applies, and cautioning that "if the owner or operator proceeds without a reviewing authority determination and if we later find that he or she made an incorrect determination on its own, the owner or operator faces potentially serious enforcement consequences").

2. Petitioners are the owners and operators of the Monroe Power Plant in Monroe, Michigan. Pet. App. 71a. In 2010, petitioners planned a $65 million overhaul of one of the emission units at that facility. *Ibid.* Before beginning work, petitioners "projected a post-project emissions increase of 3,701 tons per year of sulfur dioxide and 4,096 tons per year of nitrogen oxides," both of which are regulated air pollutants. *Ibid.* The roughly 4000-ton increase in the emissions of each of those pollutants was approximately 100 times greater than the 40-ton-per-year threshold that triggers the permitting requirement under the regulations. *Ibid.*; see 40 C.F.R. 52.21(b)(23). Petitioners, however, took the view "that the entire emissions increase fell under the demand growth exclusion," and they commenced construction without seeking a permit. Pet. App. 71a.

The EPA learned of the project two months after construction began. Pet. App. 72a. Shortly thereafter, the EPA issued a notice of violation, contending that the project should have been classified as a "major modification" for which a permit was required. *Ibid.* In August 2010, following unsuccessful efforts to resolve the dispute without litigation, and shortly after petitioners had finished their unpermitted construction, the United States filed an enforcement action against them in district court. *Id.* at 72a-73a. During discovery, an expert witness for the government explained that petitioners' reliance on the demand growth exclusion was unwarranted because, based on petitioners' own computer modeling, the project would directly lead to increased pollution by enhancing the availability of the refurbished unit, causing it to run more and pollute more. See Gov't C.A. Br. 36-37. The district court granted summary judgment to petitioners, however, on the theory that the determination whether the project was a "major modification" under the preconstruction program regulations could be made only on the basis of postconstruction emissions data. Pet. App. 96a-97a.

3. The court of appeals reversed, holding that a "preconstruction projection is subject to an enforcement action by EPA to ensure that the projection is made pursuant to the requirements of the regulations." Pet. App. 80a; see *id.* at 62a-80a. The court held that the EPA is not "categorically prevented from challenging even blatant violations of its regulations until long after modifications are made." *Id.* at 64a. It reasoned that if such a bar existed, the scheme "would cease to be a preconstruction review program." *Id.* at 74a-75a. The court explained that, under the regulatory scheme, the operator "has to make projections according to the requirements for such projections contained in the regulations." *Id.* at 75a. "If the operator does not do so," the court continued, "it is subject to an enforcement proceeding." *Ibid.*

The court of appeals observed that petitioners had "conceded at oral argument that EPA could use its enforcement powers to force operators to make the projection." Pet. App. 76a. The court concluded that the agency's "powers must also extend to ensuring that operators follow the requirements in making those projections." *Ibid.* The court noted in particular petitioners' statement at oral argument that, " 'if the operator had misread the rules and used 400 tons per year instead of

40 tons per year as the significance threshold, they would have filed an improper notification, an improper projection, and the agency could then make them do the projection right.'" *Id.* at 76a-77a (brackets and citation omitted).

Judge Batchelder, while "agree[ing] with much of the majority opinion," dissented on the ground that any dispute about preconstruction projections had been mooted by postconstruction data showing no increase in emissions. Pet. App. 81a; see *id.* at 81a-85a.

4. On remand, the district court again granted summary judgment, and partial final judgment under Federal Rule of Civil Procedure 54(b), for petitioners on the relevant claims. Pet. App. 57a-61a; see *id.* at 52a-54a. The court construed an admonishment by the court of appeals against "'second-guess[ing]'" the operator's calculations as a directive that the district court's scrutiny be limited to a "surface review" or a "cursory examination" of a source's projections. *Id.* at 59a (citation omitted). The district court accordingly believed that it was required to accept the validity of petitioners' assertion that the demand growth exclusion entirely canceled out its projected 8000-ton emissions increases. *Id.* at 59a-60a. The court also concluded in the alternative that the absence of measured postconstruction emissions increases entitled petitioners to prevail. *Id.* at 60a.

The court of appeals again reversed and remanded for further proceedings. Pet. App. 1a-47a. Judge Daughtrey wrote the lead opinion, which Judge Batchelder joined as to the result. *Id.* at 1a-12a. Judge Daughtrey found "genuine disputes of material fact that preclude summary judgment for [petitioners] regarding [their] compliance with [the] statutory preconstruction requirements and with agency regulations implementing those provisions." *Id.* at 11a. She expressed her own view that petitioners' preconstruction projections were flawed because, *inter alia*, petitioners had "fail[ed] to carry [their] burden to set out a factual basis for [their] demand-growth exclusion." *Id.* at 9a. She also emphasized that "the panel unanimously agree[d]," based on the precedential and law-of-the-case effects of the court of appeals' decision in the prior appeal, "that actual post-construction emissions have no bearing on the question of whether [petitioners'] preconstruction projections complied with the regulations." *Id.* at 11a-12a.

Judge Batchelder concurred in the judgment. Pet. App. 13a-23a. She stated that the panel's prior opinion "clearly requires that we reverse the district court's grant of summary judgment to [petitioners] and remand for reconsideration consistent with that prior opinion." *Id.* at 14a; see *id.* at 13a-23a. She observed that, after the first remand, the government had "reframed its claims" against petitioners to allege "noncompliance with particular regulations," including allegations that petitioners had failed to "base [their] predictions on 'all relevant information'" and had "ignored [their] own modeling when claiming that any increase was due to demand increases." *Id.* at 22a (quoting 40 C.F.R. 52.21(b)(41)(ii)(*a*)). She concluded that "this is a far more legitimate challenge." *Ibid.*

Judge Rogers dissented, expressing the view that "the undisputed facts establish that [petitioners] complied with the basic requirements of the regulations for making projections." Pet. App. 24a-25a; see *id.* at 24a-47a.

ARGUMENT

Petitioners contend (Pet. 20-30) that the EPA categorically cannot pursue an enforcement action for unlawfully commencing construction without a permit unless the EPA shows that emissions in fact increased after the unpermitted construction. The court of appeals correctly rejected that categorical contention, in recognition of the interpretation of the CAA and its implementing regulations under which the EPA proceeded when it brought this enforcement action. That interpretation is a reasonable construction of the regulations and the underlying statute, and as such is entitled to deference.[2] The court's decision does not conflict with any decision of this Court or any other court of appeals. Further review of this case, particularly in its current interlocutory posture, is not warranted.

1. "[T]he 'construction' requiring a * * * permit under" the relevant CAA provisions "include[s] * * * a 'modification'" of an existing pollution source. *Environmental Def.* v. *Duke Energy Corp.*, 549 U.S. 561, 568 (2007); see *Alaska Dep't of Envtl. Conservation* v. *EPA*,

---

[2] On March 28, 2017, the President issued Executive Order No. 13,783, "Promoting Energy Independence and Economic Growth," which recognizes the "national interest" in ensuring "affordable, reliable, safe, secure, and clean" energy production from domestic sources, and which directs the EPA to consider the effect of its regulations pertaining to domestic energy production. 82 Fed. Reg. 16,093 (Mar. 31, 2017). Consistent with that directive, the agency is currently reviewing its New Source Review policies and regulations. See EPA, *Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783*, at 1-2 (Oct. 25, 2017), https://www.epa.gov/sites/production/files/2017-10/documents/eo-13783-final-report-10-25-2017.pdf. The issues underlying this enforcement action are among those under consideration. The agency intends to address its prospective approach to New Source Review through a combination, as appropriate, of statements of enforcement policy, interpretation of existing regulations, and, potentially, proposals for regulatory reform.

540 U.S. 461, 472 (2004) (*ADEC*) ("No such facility may be constructed or modified unless a permit prescribing emission limitations has been issued for the facility."). Compliance with the Act accordingly requires a prospective determination, before construction commences, about whether a particular alteration to an existing pollution source should be considered a "modification" under the statute. If such a determination were wholly retrospective, neither the EPA nor a regulated entity would know ex ante whether a permit was required.

The structure and substance of the CAA, along with the EPA's current regulations and the agency's interpretations of those regulations at the time that it brought this enforcement action, reflect the prospective nature of the permit determination. The requirement to obtain a permit, and the procedural and substantive prerequisites for doing so, are set forth in a section entitled "[p]reconstruction requirements." 42 U.S.C. 7475(a). In addition, the EPA has broad authority under the Act to halt construction before it commences or is complete. "In notably capacious terms, Congress armed EPA with authority to issue orders stopping construction when 'a State is not acting in compliance with any CAA requirement or prohibition . . . relating to the construction of new sources or the modification of existing sources,' [42 U.S.C.] 7413(a)(5), or when 'construction or modification of a major emitting facility . . . does not conform to the requirements of [this part],' [42 U.S.C.] 7477." *ADEC*, 540 U.S. at 484 (brackets omitted). The courts of appeals have accordingly recognized that a violation of the Act can occur "when construction commences without a permit in hand." *United States* v. *Midwest Generation, LLC*, 720 F.3d 644, 647 (7th Cir.

2013); see *United States* v. *EME Homer City Generation, L.P.*, 727 F.3d 274, 285 (3d Cir. 2013); *Texas* v. *EPA*, 726 F.3d 180, 190 (D.C. Cir. 2013); *Sierra Club* v. *Otter Tail Power Co.*, 615 F.3d 1008, 1014 (8th Cir. 2010); *CleanCOALition* v. *TXU Power,* 536 F.3d 469, 478 (5th Cir.), cert. denied, 555 U.S. 1049 (2008); *National Parks & Conservation Ass'n, Inc.* v. *Tennessee Valley Auth.*, 502 F.3d 1316, 1322 (11th Cir. 2007), cert. denied, 554 U.S. 917 (2008).

EPA regulations implementing the statute similarly provide that no "major modification" can proceed "without a permit that states that the * * * major modification will meet" relevant requirements, 40 C.F.R. 52.21(a)(2)(iii), and that any source that "commences construction" of such a modification without approval "shall be subject to appropriate enforcement," 40 C.F.R. 52.21(r)(1). The regulations accordingly require that "an operator must project post-change emissions" in order to determine whether "a proposed change" would "require a permit." Pet. App. 66a; see 40 C.F.R. 52.21(a)(2)(iv)(*c*). In the context of the CAA's preconstruction permitting scheme, a determination of the lawfulness of particular unpermitted construction may include consideration of whether, "at the time of the projects," the operator "expected, or should have expected, that its modifications would result in" emissions increases. *United States* v. *Alabama Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013); see *United States* v. *Cinergy Corp.*, 623 F.3d 455, 459 (7th Cir. 2010) (relevant analysis turns on whether modification "'[w]ould,' not 'did' [result in an increase], because the permit must be obtained before the modification is made, and so the effect on emissions is a prediction rather than an observation").

2. Petitioners acknowledged below, and do not dispute now, "that EPA could use its enforcement powers to force operators to make the projection." Pet. App. 76a. Petitioners likewise acknowledged below, and do not dispute now, that the EPA could, in at least some circumstances, also use its enforcement powers to ensure that operators "do the projection right"—*e.g.*, by requiring recalculation when an operator has "misread" the regulatory thresholds that trigger the permitting requirement. *Id.* at 76a-77a (citation omitted); see *New York* v. *U.S. EPA*, 413 F.3d 3, 35 (D.C. Cir. 2005) (per curiam) (recognizing that oversight is necessary to prevent source from "overstating the demand growth exclusion"); *Wisconsin Elec. Power Co.* v. *Reilly*, 893 F.2d 901, 917 (7th Cir. 1990) (recognizing "that the EPA cannot reasonably rely on a utility's own unenforceable estimates of its annual emissions"). Petitioners' current contention—that the statute forecloses a reading under which the outcome of an enforcement action that challenges unpermitted construction can turn on any factor other than a post hoc examination of the completed project—cannot be squared with those acknowledgments, or with the statutory or regulatory scheme as interpreted by the agency at the time it brought this enforcement action.

a. The statute and the current regulations, as interpreted by the EPA at the time that it brought this enforcement action, do not allow an operator to disregard the regulatory projection requirements, commence construction without the permit a valid projection would require, and then argue based solely on postconstruction emission rates that its earlier actions were lawful. Petitioners suggest (Pet. 21) that such a result is mandated by the use of the present tense in the statutory definition of "modification," which refers to a change that "increases" emissions. That suggestion disregards the background rule under the Dictionary Act, 1 U.S.C. 1, that "unless the context indicates otherwise * * * words used in the present tense include the future as well as the present."

Here, the context allows an interpretation of "increases" that relies primarily on preconstruction projections, rather than focusing solely on postconstruction measurements. The CAA requires, for example, that the EPA must bring an action "to *prevent* the construction or modification of a major emitting facility which does not conform to the [statutory] requirements." 42 U.S.C. 7477 (emphasis added). A suit to "prevent" construction can only be brought before postconstruction data are available. See *ibid.* (similarly requiring action to prevent a "proposed" unlawful modification); 42 U.S.C. 7413 (authorizing additional civil and criminal enforcement).

Petitioners' reliance on certain phrases in the regulations is similarly unavailing. As petitioners note (*e.g.*, Pet. 5, 21), a project "is not a major modification if it does not cause a significant emissions increase," and even then "is a major modification only if it also results in a significant net emissions increase." 40 C.F.R. 52.21(a)(2)(iv)(*a*). But petitioners' focus on that language disregards the regulatory directive that, for purposes of the permit requirement, projections made "before beginning actual construction" must be used to determine whether such increases "will occur" for purposes of the permit requirement. 40 C.F.R. 52.21(a)(2)(iv)(*b*); see 40 C.F.R. 52.21(a)(2)(iv)(*c*) and (b)(3). Petitioners also focus (*e.g.*, Pet. 13) on regulatory language stating that, "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase." 40 C.F.R. 52.21(a)(2)(iv)(*b*). But pursuant to the EPA's interpretation of its regulations as applied in this enforcement action, that provision simply expands the regulatory definition of "major modification" to include projects that unexpectedly increase emissions. Under this reading, the regulatory provision would have no bearing on whether a project that is expected to increase emissions requires a preconstruction permit.

b. Contrary to petitioners' contention, the absence of an immediately measurable increase in emissions upon completion of a project does not necessarily validate an operator's prior unlawful decision to commence construction without a permit that would have been required by proper preconstruction projections. See, *e.g.*, 40 C.F.R. 52.21(r)(1) (requiring a permit before commencing construction projected to result in emissions increases). Neither the Act nor the regulations require such an approach. *Inter alia*, the absence of measurable increases within an arbitrarily limited time window does not prove that the EPA's projections were incorrect, or that no increases in emissions will in fact occur. It may instead reflect, for example, that the operator is not yet operating the source at its full future capacity during the pendency of the enforcement action. Here, for example, shortly after the EPA's enforcement action was filed, the district court ordered petitioners "not to use" the refurbished unit "'to any extent that is greater than it was utilized' prior to the completion of the projects." Pet. App. 31a.

Under the EPA's interpretation and application in this case of the permitting scheme in the statute and the present regulations, an operator's preconstruction projections do not preclude the agency's enforcement of the preconstruction requirements that the scheme reasonably imposes. Contrary to petitioners' suggestion (Pet. 24-26), an enforcement action premised on allegations that an operator failed to comply with the projection regulations is consistent with due process. Petitioners had clear notice of the projection regulations. Cf. *Good Samaritan Hosp.* v. *Shalala*, 508 U.S. 402, 418-419 (1993) (upholding agency interpretation even though rule could have had a "more exact mode of calculating" a particular cost factor). They also had clear notice of the data produced by their own computer models, which provide the basis for the government's claim that the regulations were disregarded. See pp. 5-6, *supra.* In any event, petitioners did not press any due process argument below; the court of appeals did not pass on such an argument; and review of that argument in the first instance by this Court would not be warranted. See, *e.g.*, *Adickes* v. *S. H. Kress & Co.*, 398 U.S. 144, 147 n.2 (1970).

3. Petitioners do not identify any decision of this Court or another court of appeals that has directly addressed the question presented here and reached a different result than did the court below. See Pet. 23 (acknowledging that "the precise question presented differed among" the cases it cites).

The three decisions that petitioners cite as support for their reading of the statute and regulations in fact support the opposite interpretation. This Court's decision in *Environmental Defense* v. *Duke Energy Corp.*, *supra*, observed that the regulations define "major modification" in terms of the emissions that "would result" from a project's completion, 549 U.S. at 568, and it allowed the government to proceed on a claim that certain "projects would have been projected to result in" emissions increases, *id.* at 571 (citation omitted). The Seventh Circuit's decision in *Wisconsin Electric Power Co.* v. *Reilly*, *supra*, similarly recognized that in determining whether a project is a major modification, "the question is whether [the] renovation project *will* result in 'a significant net emissions increase.'" 893 F.2d at 916 (emphasis added; citation omitted). The court simply determined that the agency had misapplied the then-existing regulations in finding that standard to have been met. See *id.* at 916-918. And in *New York* v. *U.S. EPA*, *supra*, the D.C. Circuit concluded that "Congress directed the agency to measure emissions increases in terms of changes in actual emissions," as opposed to "looking to whether 'emissions limitations' have changed," but it upheld the EPA's "use of * * * projected future actual emissions * * * in measuring emissions increases." 413 F.3d at 10; see *id.* at 38-40.

4. The current interlocutory posture of this case further counsels against granting a writ of certiorari at this time. See *Hamilton-Brown Shoe Co.* v. *Wolf Bros. & Co.*, 240 U.S. 251, 258 (1916) (observing that the interlocutory nature of a case "alone furnishe[s] sufficient ground for the denial" of the petition for a writ of certiorari); *Virginia Military Inst.* v. *United States*, 508 U.S. 946, 946 (1993) (Scalia, J., respecting the denial of the petition for a writ of certiorari) ("We generally await final judgment in the lower courts before exercising our certiorari jurisdiction."). The court of appeals' decision returns the case to the district court to hear evidence on whether a permit was required. See Pet. App. 11a ("Viewing the facts in the light most favorable to the EPA, we conclude that there are genuine disputes of material fact that preclude summary judgment for

[petitioners] regarding [their] compliance with [the relevant] statutory preconstruction requirements and with agency regulations implementing those provisions."). If petitioners are ultimately found liable after those factual disputes are resolved, they can seek further review of the question presented following the entry of final judgment.

In addition, as noted above (see p. 9 n.2, *supra*), the EPA is currently reviewing its New Source Review policies and regulations. That review may result in changes to the agency's regulatory approach. The possibility of such changes provides a further reason to deny the petition.

CONCLUSION

The petition for a writ of certiorari should be denied.

Respectfully submitted.

NOEL J. FRANCISCO
Solicitor General
JEFFREY H. WOOD
Acting Assistant Attorney General
ROBERT J. LUNDMAN
THOMAS A. BENSON
Attorneys

NOVEMBER 2017

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF	)	PETITION NO. VI-2013-10
	)	
BIG RIVER STEEL, LLC	)	
OSCEOLA, ARKANSAS	)	ORDER RESPONDING TO
	)	PETITION REQUESTING
PERMIT NO. 2305-AOP-R0	)	OBJECTION TO THE ISSUANCE OF
	)	A TITLE V OPERATING PERMIT
ISSUED BY THE ARKANSAS DEPARTMENT OF	)	
ENVIRONMENTAL QUALITY	)	
	)	

ORDER DENYING A PETITION FOR OBJECTION TO PERMIT

I. INTRODUCTION

The U.S. Environmental Protection Agency (EPA) received a petition dated October 9, 2013, (the Petition) from Nucor Steel-Arkansas and Nucor-Yamato Steel Company (collectively the Petitioner), pursuant to section 505(b)(2) of the Clean Air Act (CAA or Act), 42 U.S.C. § 7661d(b)(2). The Petition requests that the EPA object to final Permit No. 2305-AOP-R0 (the Permit) issued by the Arkansas Department of Environmental Quality (ADEQ) to Big River Steel, LLC for a steel mill (BRS or the facility) in Osceola, Mississippi County, Arkansas. The operating permit was issued pursuant to title V of the CAA, CAA §§ 501–507, 42 U.S.C. §§ 7661–7661f, and Arkansas Pollution Control & Ecology Commission (APC&EC) Regulation 26. *See also* 40 C.F.R. part 70 (title V implementing regulations). This type of operating permit is also referred to as a title V permit or part 70 permit.

Based on a review of the Petition and other relevant materials, including the Permit, the permit record, and relevant statutory and regulatory authorities, and as explained further below, the EPA denies the Petition requesting that the EPA object to the Permit.

II. STATUTORY AND REGULATORY FRAMEWORK

A. Title V Permits

Section 502(d)(l) of the CAA, 42 U.S.C. § 766la(d)(1), requires each state to develop and submit to the EPA an operating permit program to meet the requirements of title V of the CAA and the EPA's implementing regulations at 40 C.F.R. part 70. The state of Arkansas submitted a title V operating permit program on October 29, 1993. The EPA granted interim approval of the Arkansas title V program in 1995. 60 Fed. Reg. 46771 (September 8, 1995). The EPA granted final approval of the Arkansas title V program in 2001. 66 Fed. Reg. 51312 (October 9, 2001). The program is currently codified in APC&EC Regulation 26.

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable implementation plan. CAA §§ 502(a), 504(a), 42 U.S.C. §§ 7661a(a), 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements, but does require permits to contain adequate monitoring, recordkeeping, reporting, and other requirements to assure sources' compliance with applicable requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992); *see* CAA § 504(c), 42 U.S.C. § 7661c(c). One purpose of the title V program is to "enable the source, States, the EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." 57 Fed. Reg. at 32251. Thus, the title V operating permit program is a vehicle for compiling the air quality control requirements as they apply to the facility's emission units and for providing adequate monitoring, recordkeeping, and reporting to assure compliance with such requirements.

B. Review of Issues in a Petition

State and local permitting authorities issue title V permits pursuant to their EPA-approved title V programs. Under CAA § 505(a), 42 U.S.C. § 7661d(a), and the relevant implementing regulations found at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to the EPA for review. Upon receipt of a proposed permit, the EPA has 45 days to object to final issuance of the proposed permit if the EPA determines that the proposed permit is not in compliance with applicable requirements under the Act. CAA § 505(b)(1), 42 U.S.C. § 7661d(b)(1); *see also* 40 C.F.R. § 70.8(c). If the EPA does not object to a permit on its own initiative, any person may petition the Administrator, within 60 days of the expiration of the EPA's 45-day review period, to object to the permit. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d).

The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting authority (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d)). In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(l).[1] Under section 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to the EPA.[2]

---

[1] *See also New York Public Interest Research Group, Inc. v. Whitman*, 321 F.3d 316, 333 n.11 (2d Cir. 2003) (*NYPIRG*).

[2] *WildEarth Guardians v. EPA*, 728 F.3d 1075, 1081–82 (10th Cir. 2013); *MacClarence v. EPA*, 596 F.3d 1123, 1130–33 (9th Cir. 2010); *Sierra Club v. EPA*, 557 F.3d 401, 405–07 (6th Cir. 2009); *Sierra Club v. Johnson*, 541 F.3d 1257, 1266–67 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677–78 (7th Cir. 2008); *cf. NYPIRG*, 321 F.3d at 333 n.11.

The petitioner's demonstration burden is a critical component of CAA § 505(b)(2). As courts have recognized, CAA § 505(b)(2) contains both a "discretionary component," to determine whether a petition demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act, and a nondiscretionary duty to object where such a demonstration is made. *Sierra Club v. Johnson*, 541 F.3d at 1265–66 ("[I]t is undeniable [that CAA § 505(b)(2)] also contains a discretionary component: it requires the Administrator to make a judgment of whether a petition demonstrates a permit does not comply with clean air requirements."); *NYPIRG*, 321 F.3d at 333. Courts have also made clear that the Administrator is only obligated to grant a petition to object under CAA § 505(b)(2) if the Administrator determines that the petitioner has demonstrated that the permit is not in compliance with requirements of the Act. *Citizens Against Ruining the Environment*, 535 F.3d at 677 (stating that § 505(b)(2) "clearly obligates the Administrator to (1) determine whether the petition demonstrates noncompliance and (2) object *if* such a demonstration is made" (emphasis added)).[3] When courts have reviewed the EPA's interpretation of the ambiguous term "demonstrates" and its determination as to whether the demonstration has been made, they have applied a deferential standard of review. *See, e.g., MacClarence*, 596 F.3d at 1130–31.[4] Certain aspects of the petitioner's demonstration burden are discussed below; however, a more detailed discussion can be found in *In the Matter of Consolidated Environmental Management, Inc., Nucor Steel Louisiana*, Order on Petition Nos. VI-2011-06 and VI-2012-07 at 4–7 (June 19, 2013) *(Nucor II Order)*.

The EPA has looked at a number of criteria in determining whether a petitioner has demonstrated noncompliance with the Act. *See generally Nucor II Order* at 7. For example, one such criterion is whether the petitioner has addressed the state or local permitting authority's decision and reasoning. The EPA expects the petitioner to address the permitting authority's final decision, and the permitting authority's final reasoning (including the state's response to comments), where these documents were available during the timeframe for filing the petition. *See MacClarence*, 596 F.3d at 1132–33.[5] Another factor the EPA has examined is whether a petitioner has provided the relevant analyses and citations to support its claims. If a petitioner does not, the EPA is left to work out the basis for petitioner's objection, contrary to Congress's express allocation of the burden of demonstration to the petitioner in CAA § 505(b)(2). *See MacClarence*, 596 F.3d at 1131 ("[T]he Administrator's requirement that [a title V petitioner] support his allegations with legal reasoning, evidence, and references is reasonable and persuasive.").[6] Relatedly, the EPA has pointed out in numerous orders that, in particular cases,

---

[3] *See also Sierra Club v. Johnson*, 541 F.3d at 1265 ("Congress's use of the word 'shall' . . . plainly mandates an objection *whenever* a petitioner demonstrates noncompliance." (emphasis added)).

[4] *See also Sierra Club v. Johnson*, 541 F.3d at 1265–66; *Citizens Against Ruining the Environment*, 535 F.3d at 678.

[5] *See also, e.g., In the Matter of Noranda Alumina, LLC*, Order on Petition No. VI-2011-04 at 20–21 (December 14, 2012) (denying a title V petition issue where petitioners did not respond to the state's explanation in response to comments or explain why the state erred or the permit was deficient); *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9 at 41 (June 22, 2012) (*Kentucky Syngas Order*) (denying a title V petition issue where petitioners did not acknowledge or reply to the state's response to comments or provide a particularized rationale for why the state erred or the permit was deficient); *In the Matter of Georgia Power Company*, Order on Petitions, at 9–13 (January 8, 2007) (*Georgia Power Plants Order*) (denying a title V petition issue where petitioners did not address a potential defense that the state had pointed out in the response to comments).

[6] *See also In the Matter of Murphy Oil USA, Inc.*, Order on Petition No. VI-2011-02 at 12 (September 21, 2011) (denying a title V petition claim where petitioners did not cite any specific applicable requirement that lacked

general assertions or allegations did not meet the demonstration standard. *See, e.g., In the Matter of Luminant Generation Co., Sandow 5 Generating Plant*, Order on Petition Number VI-2011-05 at 9 (January 15, 2013) (*Luminant Sandow Order*).[7] Also, the failure to address a key element of a particular issue presents further grounds for the EPA to determine that a petitioner has not demonstrated a flaw in the permit. *See, e.g., In the Matter of EME Homer City Generation LP and First Energy Generation Corp*, Order on Petition Nos. III-2012-06, III-2012-07, and III-2013-02 at 48 (July 30, 2014) (*Homer City Order*).[8]

The information that the EPA considers in making a determination whether to grant or deny a petition submitted under 40 C.F.R. § 70.8(d) on a proposed permit generally includes, but is not limited to, the administrative record for the proposed permit and the petition, including attachments to the petition. The administrative record for a particular proposed permit includes the draft and proposed permits; any permit applications that relate to the draft or proposed permits; the statement of basis for the draft and proposed permits; the permitting authority's written responses to comments, including responses to all significant comments raised during the public participation process on the draft permit; relevant supporting materials made available to the public according to 40 C.F.R. § 70.7(h)(2); and all other materials available to the permitting authority that are relevant to the permitting decision and that the permitting authority made available to the public according to § 70.7(h)(2). If a final permit and a statement of basis for the final permit are available during the agency's review of a petition on a proposed permit, those documents may also be considered as part of making a determination whether to grant or deny the petition.

C. New Source Review

The major New Source Review (NSR) program is comprised of two core types of preconstruction permit requirements for major stationary sources. Part C of title I of the CAA establishes the Prevention of Significant Deterioration (PSD) program, which applies to new major stationary sources and major modifications of existing major stationary sources for pollutants for which an area is designated as attainment or unclassifiable for the national ambient air quality standards (NAAQS) and other pollutants regulated under the CAA. CAA §§ 160–169, 42 U.S.C. §§ 7470–7479. Part D of title I of the Act establishes the major nonattainment NSR (NNSR) program, which applies to new major stationary sources and major modifications of existing major stationary sources for those NAAQS pollutants for which an area is designated as nonattainment. CAA §§ 171–193, 42 U.S.C. §§ 7501–7515.

At issue in this Order is the PSD program, which requires a major stationary source to obtain a PSD permit before beginning construction of a new facility or undertaking certain modifications. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1); CAA § 169(2)(C), 42 U.S.C. § 7479(2)(C). For a

---

required monitoring); *In the Matter of Portland Generating Station*, Order on Petition, at 7 (June 20, 2007) (*Portland Generating Station Order*).

[7] *See also Portland Generating Station Order* at 7 ("[C]onclusory statements alone are insufficient to establish the applicability of [an applicable requirement]."); *In the Matter of BP Exploration (Alaska) Inc., Gathering Center #1*, Order on Petition Number VII-2004-02 at 8 (April 20, 2007); *Georgia Power Plants Order* at 9–13; *In the Matter of Chevron Products Co., Richmond, Calif. Facility*, Order on Petition No. IX-2004–10 at 12, 24 (March 15, 2005).

[8] *See also In the Matter of Hu Honua Bioenergy*, Order on Petition No. IX-2011-1 at 19–20 (February 7, 2014); *Georgia Power Plants Order* at 10.

source subject to the PSD permitting program, several requirements must be addressed before a permitting authority may issue a permit, including: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) the application of the Best Available Control Technology (BACT) for each pollutant subject to regulation under the Act. CAA §§ 165(a)(3), (4), 42 U.S.C. §§ 7475(a)(3), (4); 40 C.F.R. § 52.21(j), (k).

The EPA has two largely identical sets of regulations implementing the PSD program. One set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a state implementation plan (SIP). The other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program, which applies in areas without a SIP-approved PSD program. The EPA has approved the Arkansas PSD program as part of its SIP. *See* 40 C.F.R. § 52.170(c) (listing EPA-approved PSD provisions contained in APC&EC Regulation 19, Chapter 9). The EPA-approved Arkansas PSD regulations incorporate the federal PSD regulations in 40 C.F.R. § 52.21 (a)(2) through (bb) as of November 29, 2005 with certain exceptions not relevant to the claims in the Petition. *See* APC&EC Reg. 19.904.

III. BACKGROUND

A. The Big River Steel Facility

The BRS facility is a new steel mill in Osceola, Mississippi County, Arkansas. When operational, the BRS facility will consist of two Electric Arc Furnaces to melt scrap iron and steel, each of which will produce up to 1.7 million tons of steel annually, Ladle Metallurgy Furnaces to adjust the chemistry, a Rurhstahl Heraeus Degasser and boiler for further refinement, and casters. The output steel will be further processed on a pickling line, galvanizing lines, annealing furnaces and lines, a decarburizing line, and several other processes. The facility also has emergency generators, cooling towers, raw and finished material handling, and other miscellaneous sources. Among other requirements, the BRS facility is subject to PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM, PM_{10}, and $PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC), lead, and greenhouse gases (GHG).

B. Permitting History

BRS filed an application with ADEQ for both a PSD preconstruction permit and a title V operating permit on January 30, 2013.[9] ADEQ found this first application incomplete, and BRS

[9] The facility's title V permit, issued under APC&EC Regulation 26, was processed concurrently with a PSD permit, issued under APC&EC Regulation 19. Both permits were issued in a single permit document (titled Permit No. 2305-AOP-R0), due to the structure of Arkansas's EPA-approved regulations governing the procedures for issuance of title V permits and NSR permits. As the EPA explained in approving the Arkansas title V program, "Chapter 11 of Regulation 19 . . . addresses the NSR permitting procedures for major sources which are also subject to Regulation 26—Regulations of the Arkansas Operating Permit Program. . . . Chapter 11 requires major sources which are subject to Regulation 26 to also have their permit applications processed in accordance with the procedures contained in Regulation 26, which are incorporated by reference. Thus, Chapter 11 creates the connection between the PSD and title V programs to allow Arkansas to issue one permit to its sources which are defined as major under both programs." 66 Fed. Reg. 51312, 51315 (October 9, 2001) (EPA approval of Arkansas

submitted a second permit application on March 5, 2013. Although ADEQ deemed this second application administratively complete on March 14, 2013, after discussion between ADEQ and BRS, ADEQ requested that BRS submit a third permit application. BRS submitted its third application on June 21, 2013. ADEQ issued public notice of the merged draft PSD preconstruction permit and draft title V operating permit on June 27, 2013, subject to a public comment period that ended on July 29, 2013, and a public hearing held on July 30, 2013. The EPA's 45-day review period of the proposed title V operating permit ran concurrently with the public comment period, and ended on August 11, 2013. The EPA did not object to the title V permit. ADEQ issued final Permit No. 2305-AOP-R0 along with its response to comments (RTC) document on September 18, 2013.[10]

C. Timeliness of Petition

Pursuant to the CAA, if the EPA does not object to a proposed title V permit during its 45-day review period, any person may petition the Administrator within 60 days after the expiration of the 45-day review period to object. 42 U.S.C § 7661d(b)(2). The EPA's 45-day review period expired on August 11, 2013. Thus, any petition seeking the EPA's objection to the Permit was due on or before October 10, 2013. The Petition was dated October 9, 2013, and the EPA finds that the Petitioner timely filed the Petition.[11]

IV. DETERMINATIONS ON CLAIMS RAISED BY THE PETITIONER

The Petitioner specifically enumerated twelve claims, each of which is addressed below.[12] Because 11 of the claims in the Petition concern determinations related to the PSD permit issued by ADEQ, those claims are addressed together immediately below. The remaining two claims—Claims C.4 and C.5—are addressed individually in following subsections.

---

title V rules); *see also* 65 Fed. Reg. 61103, 61104 (October 16, 2000) (EPA approval of Arkansas PSD rules into the Arkansas SIP).

[10] ADEQ subsequently processed an administrative amendment on August 31, 2015, to add four insignificant activities to the Permit. As such, Permit No. 2305-AOP-R0 has technically been superseded by Permit No. 2305-AOP-R1. This administrative amendment did not alter permitted emission rates or any of the permit terms or conditions that the EPA is considering in this Order. Therefore, the EPA is responding to the Petition as it relates to the final version of Permit No. 2305-AOP-R0 that formed the basis of the Petition.

[11] After submitting the Petition, the Petitioner submitted a supplement to the Petition on April 21, 2014 (Supplemental Petition). The Supplemental Petition claims to provide additional details in support of the Petition based on information that arose in the course of a state administrative appeal process that began after the Petition was filed. The EPA is not responding to the Supplemental Petition in this Order because it was not submitted within 60 days of the end of the EPA's 45-day review period, as required by the CAA. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). The assertion "that it was impracticable to raise" certain information during the public comment period does not require the EPA to respond to such information included as part of a Supplemental Petition submitted after the 60-day statutory petition deadline, contrary to the assertions of the Petitioners. *See id*; Supplemental Petition at 1–2.

[12] The Petitioner also summarized six claims in an introductory section of the Petition, the majority of which directly correspond to one of the enumerated claims. However, the fourth summary claim, concerning GHG BACT limits, is not discussed elsewhere in the Petition. We, therefore, consider that the Petition contains 13 claims – all of which are addressed below.

The Petitioner's Claims Related to PSD Determinations[13]

Petitioner's Claims: Of the Petitioner's claims related to PSD determinations made by ADEQ, the Petitioner first raises four specific claims challenging the adequacy of the PSD air quality impacts modeling conducted in order to demonstrate that the BRS facility would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. Petition at 11. In each of these modeling claims, the Petitioner contends that $PM_{2.5}$ emissions from the BRS facility should have been modeled differently. In Claim A.1, the Petitioner claims that ADEQ conducted an inadequate review of background air quality data. *Id.* at 12–16. Specifically, the Petitioner asserts that ADEQ did not adequately justify why an air quality monitor located in Dyersburg, Tennessee, was representative of the background air quality in the area of the BRS facility. *Id.* In Claim A.2, the Petitioner alleges that the $PM_{2.5}$ modeling was deficient because it excluded certain areas from the analysis. *Id.* at 16–17. Specifically, the Petitioner argues that ADEQ inappropriately excluded certain areas where $PM_{2.5}$ emissions from BRS were projected to have an insignificant impact and that ADEQ used inappropriate impact levels to assess the significance of impacts. *See id.* In Claim A.3, the Petitioner claims that the $PM_{2.5}$ modeling is deficient because ADEQ failed to include secondary formation of $PM_{2.5}$ (i.e., $PM_{2.5}$ emissions formed in the atmosphere from the facility's SO_2 and NO_x emissions), and instead only included $PM_{2.5}$ directly emitted by the facility. *Id.* at 18–19. In Claim A.4, the Petitioner asserts there are discrepancies among different modeled $PM_{2.5}$ annual impact values in or associated with the $PM_{2.5}$ modeling. *See id.* at 19–20.

Next, in Claim B, the Petitioner claims that ADEQ and BRS failed to properly carry out two types of PSD additional impacts analyses. *See id.* at 20–24. First, the Petitioner challenges the adequacy of the "analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial or other growth associated with the source." *Id.* at 20–21 (citing 42 U.S.C. § 7475(a)(6) and 40 C.F.R § 52.21(o)). Second, the Petitioner challenges the adequacy of an analysis related to the effects of the proposed project's consumption of available PSD increment on industrial and economic development in the area and alternatives to the project. *See id.* at 21 (citing APC&EC Reg. 19.904(C)).

In Claim C, the Petitioner advances seven[14] loosely related claims under the following heading: "The permit and permit application does not contain source information necessary to perform the analyses required for PSD review, does not contain the information required by Part 70 for operating permits, and was not processed properly." *Id.* at 24. Many of these claims pertain to the determination of BACT for the BRS facility. In Claim C.1, the Petitioner asserts that emission factors for natural gas combustion are conflicting and argues that the $PM_{2.5}$ BACT limit for natural gas combustion units at the BRS facility are too stringent and may not be achievable by the source. *See id.* at 25–27. In Claim C.2, the Petitioner questions the basis for the $PM_{2.5}$ BACT emission limit for electric arc furnaces at the BRS facility, again alleging that the emission limits, in this case proposed and accepted by BRS, are too stringent and may not be achievable. *Id.* at 28. In Claim C.6, the Petitioner asserts that the BACT limits for the source were established based on limits proposed by BRS and the results of modeling, "without completing the full BACT technical analysis and considering the BACT factors." *Id.* at 31–32. Additionally,

[13] This section addresses Claims A.1, A.2, A.3, A.4, B, C.1, C.2, C.3, C.6, C.7, and summary claim 4 concerning GHG BACT limits.

[14] Of the seven claims contained within Claim C, two (C.4 and C.5) are addressed individually below.

in the introductory section of the Petition, the Petitioners briefly assert that ADEQ doubled the GHG BACT limit (expressed as carbon dioxide equivalent) in the Permit without adequate explanation or justification. *Id.* at 6–7 (referred to as "summary claim 4").

Other claims within Claim C are related more generally to the adequacy of the facility's permit application. In Claim C.3, the Petitioner asserts that the permit application was incomplete because it did not reflect the final design and placement of all emission units at the facility, which the Petitioner asserts affected the validity of the $PM_{2.5}$ air quality modeling. *Id.* at 29. In Claim C.7, the Petitioner claims generally that the draft permit did not comply with public notice requirements because the permit application relied in part on plans that were to be developed and because ADEQ knew that the permit application was incomplete or contradictory. *Id.* at 32–33. The Petitioner provides an example of how "missing and confused data" related to the facility's projected air quality impacts for NO_x resulted in a draft permit that misrepresented the facility's actual performance. *Id.* at 33–34.

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on these claims.

Each of the Petitioner's claims summarized above involve determinations made by ADEQ that are based exclusively on requirements under the PSD provisions in part C of title I of the CAA and the ADEQ's corresponding EPA-approved SIP regulations. Notwithstanding that ADEQ issued a PSD permit within the same permit document as the facility's initial title V permit,[15] the Petitioner's claims discussed above relate exclusively to title I permitting requirements—including preconstruction modeling and monitoring requirements, additional impacts analyses, and BACT determinations—rather than title V permitting requirements.[16]

This presents the fundamental issue of whether decisions made in issuing a title I preconstruction permit, like the PSD permit issued to BRS, should be considered by the EPA in reviewing or considering a petition to object to a title V operating permit. The EPA has previously considered similar preconstruction permitting issues when they were raised in petitions for an EPA objection to a state-issued title V permit. However, the EPA has recently reviewed this past practice. *See In the Matter of PacifiCorp Energy Hunter Power Plant*, Order on Petition No. VIII-2016-4 (October 16, 2017) ("*PacifiCorp-Hunter Order*"). After a review of the structure and text of the CAA and the EPA's regulations in part 70, and in light of the circumstances presented by the petition at issue in the *PacifiCorp-Hunter Order*, the EPA concluded in the *PacifiCorp-Hunter Order* that the title V permitting process is not the appropriate forum to review preconstruction permitting decisions when a preconstruction permit has been duly issued. After considering the situation presented in the Petition regarding the BRS facility, the EPA has concluded that a title V petition to object is likewise not the appropriate forum for reviewing the merits of the

[15] *See* supra note 9 and accompanying text.

[16] Some of the Petitioner's claims within Claim C concerning the allegedly inadequate permit application briefly reference Arkansas's title V program rules governing the submittal of title V permit applications, including APC&EC Regulations 26.402, 26.407, and 26.501. *See* Petition at 4, 24, 25. However, none of the Petitioner's claims asserting deficiencies in the permit application involve title V requirements. Instead, these claims exclusively relate to PSD determinations made by ADEQ. The two claims involving issues related to title V requirements are discussed individually below.

preconstruction permitting requirements derived under title I of the Act in the context of a merged title I and title V program. The EPA is aware that this conclusion differs from the agency's position in prior title V petition orders involving similar circumstances. However, for the legal and policy reasons discussed below and in the *PacifiCorp-Hunter Order*, the EPA believes this position better aligns with the structure of the Act and the EPA's original understanding of the relationship between the operating and construction permitting programs under the CAA after the enactment of title V.

Section 504 of the CAA requires that title V permits "include enforceable emissions limitations and standards . . . to assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan." 42 U.S.C. § 7661c(a).[17] However, the term "applicable requirements" is not defined in the Act and the statute does not otherwise specify how to determine the "applicable requirements of this chapter" for a particular source. In accordance with Congressional direction, 42 U.S.C. § 7661a(b), the EPA developed regulations to implement the title V program, and those regulations include a definition of the term "applicable requirement."

> *Applicable requirement* means all of the following *as they apply* to the emission units in a part 70 source . . . :
> (1) Any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in part 52 of this chapter [and]
> (2) *Any* term or condition of *any* preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including Parts C or D, of the Act
> . . .

40 C.F.R. § 70.2 (emphasis added).[18] It is clear from this language that the "applicable requirements" include the terms and conditions of preconstruction permits issued under title I of

---

[17] Similar requirements appear in other parts of title V. "Schedule of compliance. The term 'schedule of compliance' means a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable implementation plan, emission standard, emission limitation, or emission prohibition" 42 U.S.C. § 7661(3). "Nothing in this subsection shall be construed to alter the applicable requirements of this chapter that a permit be obtained before construction or modification." 42 U.S.C. § 7661a(a). Permitting authorities "have adequate authority to . . . issue permits and assure compliance . . . with each applicable standard, regulation, or requirement under this chapter." 42 U.S.C. § 7661a(b)(5). The regulations to implement the program shall include a "requirement that the applicant submit with the application a compliance plan describing how the source will comply with all applicable requirements under this chapter." 42 U.S.C. § 7661b(b). However, like section 504, these sections do not specify the scope of the term "applicable requirements," or how the permitting authority or the EPA is to determine what the applicable requirements are for an individual source as part of its title V permit.

[18] Arkansas' title V regulations mirror the EPA's regulations to define applicable requirement to include: "(a) Any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in 40 CFR part 52; (b) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act." APC&EC Reg. 26. Ch. 2.

the Act. The language in section (2) of the definition of "applicable requirement" expressly includes both PSD (part C) and NNSR (part D) permits. Therefore, if a PSD permit has been issued under an approved title I program, the second section of the definition of "applicable requirement" at 40 C.F.R. § 70.2 requires that the terms and conditions of that PSD permit are included in a source's title V permit.

The Petition addressed in this Order argues that the preconstruction permit obtained by BRS does not comply with the requirements of the applicable implementation plan. As discussed in detail below, *see infra* p. 12–14, prior to the *PacifiCorp-Hunter Order*, the EPA had construed section (1) of the definition of "applicable requirement" to include both the requirement to obtain a preconstruction permit and a requirement that such a permit comply with the applicable preconstruction permitting requirements in the plan. Specifically, the EPA has read the phrase "[a]ny standard or other requirement provided for in the applicable implementation plan" to include the requirement to obtain a preconstruction permit "that in turn complies with the applicable PSD requirements under the Act." *See, e.g., In the Matter of Shintech, Inc.*, Order on Petition, Permit Nos. 2466-VO, 2467-VO, 2468-VO at 3 n.2 (September 10, 1997). But when a source *has obtained* a preconstruction permit, for purposes of writing a title V permit, this presents an ambiguity in the definition of "applicable requirement" because section (2) includes the terms and conditions of that permit. The EPA has previously interpreted its regulations to apply both sections (1) and section (2) to title I preconstruction permitting requirements after a preconstruction permit has been obtained. But this reading can lead to a requirement that a title V permitting authority or the EPA consider or reconsider, in issuing a title V permit or permit renewal or in responding to a petition, whether a validly issued preconstruction permit complies with all of the requirements of the applicable implementation plan. While such an expansive reading of section (1) may have been applied by the EPA in past title V petition responses, this leads to an incongruous result that is inefficient and can upset settled expectations—on the part of a state, an owner/operator, and the public at large—in circumstances where a source has obtained a legally enforceable preconstruction permit in accordance with the requirements of title I.

In circumstances such as those present here where a preconstruction permit has been duly obtained, the regulations should be read to mean, consistent with the EPA's contemporaneous expressions of the purpose of title V permitting, that when a permitting authority has made a source-specific permitting decision with respect to a particular construction project under title I, those decisions "define certain applicable SIP requirements for the title V source" for purposes of title V permitting. 57 Fed. Reg. 32250, 32259 (July 21, 1992). The EPA is now interpreting the part 70 regulations to mean that the issuance of a PSD permit defines the preconstruction requirements under section (1) of the definition of "applicable requirement" for the approved construction activities for the purposes of permitting under title V of the Act.[19] These source-specific permitting actions take the general preconstruction permitting requirements of the SIP—the requirement to obtain a particular type of permit and the substantive requirements that must be included in each type of permit—and evaluate at the time of the permitting decision whether and how to apply them to a proposed construction or modification. The definition of "applicable

---

[19] In this context, a PSD permit only defines the applicable requirement for purposes of title V permitting. The interpretation of title V provisions reflected in this Order does not address anyone's ability to review a determination concerning the PSD permit terms and conditions under other titles of the Act.

requirement" says that the determination of "applicable requirements" is "as they apply" to the source and includes "any term or condition of any preconstruction permits issued." 40 C.F.R. § 70.2. In issuing a preconstruction permit to a source, the permitting authority provides the terms and conditions of the preconstruction permitting requirements of the SIP "as they apply" to the source at that time for purposes of inclusion into the title V permit. *Id.* In the circumstance present here, the source-specific preconstruction permit issued by ADEQ determined, for purposes of title V permitting for the BRS facility, the preconstruction requirements of the Arkansas SIP under section (1) of the definition of "applicable requirement." When ADEQ applied those requirements of the SIP to issue the PSD preconstruction permit to BRS, it derived the source-specific "applicable requirements" for purposes of section (2) of that definition.[20]

This reading of part 70 also takes into account the authority and procedures ADEQ used to issue the title V permit for BRS. The facility's title V permit, issued under APC&EC Regulation 26, was processed concurrently with a PSD permit, issued under APC&EC Regulation 19. Both permits were issued in a single permit document (titled Permit No. 2305-AOP-R0), due to the structure of Arkansas's EPA-approved regulations governing the procedures for issuance of title V permits and preconstruction permits. As the EPA explained in approving the Arkansas title V program:

> Chapter 11 of Regulation 19 . . . addresses the NSR permitting procedures for major sources which are also subject to Regulation 26—Regulations of the Arkansas Operating Permit Program. . . . Chapter 11 requires major sources which are subject to Regulation 26 to also have their permit applications processed in accordance with the procedures contained in Regulation 26, which are incorporated by reference. Thus, Chapter 11 creates the connection between the PSD and title V programs to allow Arkansas to issue one permit to its sources which are defined as major under both programs.[21]

This makes clear that while issued within one permit document, there were in fact two permits issued by ADEQ: (1) the PSD permit under Regulation 19, and (2) the title V permit, which incorporates the terms and conditions of that PSD permit as an "applicable requirement," under Regulation 26. While ADEQ processed the PSD permit and the title V permit concurrently, this is a choice made by the state as a matter of administrative efficiency. There is no requirement under the Act that a state process a preconstruction permit concurrently with a title V permit or permit modification. The EPA does not interpret this procedural streamlining—which effectively combines the public notice, comment, and permit issuance procedures for the preconstruction permit issued under Regulation 19 and the operating permit issued under Regulation 26—to establish a public petition opportunity under title V on the preconstruction permitting determinations made in issuing the PSD permit. The CAA establishes this petition opportunity on the title V permit alone and provides a different mechanism for EPA and citizen oversight of

[20] This interpretation applies in factual circumstances like those presented in this Petition, where a permitting authority issued a source-specific title I preconstruction permit subject to public notice and comment and for which judicial review was available. The EPA is not considering at this time whether other circumstances may warrant a different approach.

[21] 66 Fed. Reg. 51312, 51315 (October 9, 2001) (EPA approval of Arkansas title V rules); *see also* 65 Fed. Reg. 61103, 61104 (October 16, 2000) (EPA approval of Arkansas PSD rules into the Arkansas SIP).

preconstruction permitting decisions under title I.[22] The EPA does not read APC&EC Regulation 19, Chapter 11 to independently establish a public petition opportunity under title V on the PSD permit issued by ADEQ where such petition opportunity would be unavailable in a circumstance where the title I and title V permitting processes were separate.

The CAA requires the EPA to object to a title V permit if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2). "The Administrator shall include in regulations under this subchapter provisions to implement" the title V petition process. *Id.* The EPA's title V regulations state that the "Administrator will object to the issuance of any proposed permit determined by the Administrator not to be in compliance with *applicable requirements* or requirements under this part." 40 C.F.R. § 70.8(c)(1) (emphasis added). If the EPA does not object during its 45-day review period, any person may petition the EPA to issue "such objection." 40 C.F.R. § 70.8(d). Under title V, the EPA only has authority to object to the title V permit issued under Regulation 26.

The Petitioner has not alleged that ADEQ did not incorporate the terms and conditions of a preconstruction permit "issued pursuant to regulations approved or promulgated through rulemaking under title I," *i.e.*, Regulation 19. 40 C.F.R. § 70.2 (definition of "applicable requirement"). Further, the Petitioner has not alleged in the claims discussed above that the monitoring, recordkeeping, or reporting found in the title V permit, issued under Regulation 26, are inadequate to assure compliance. Therefore, the Petitioner has not demonstrated in the claims discussed above that the title V permit is "not . . . in compliance with applicable requirements" or the requirements of part 70. 40 C.F.R. § 70.8(c)(1); *see* 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d). The EPA therefore denies the Petition with regard to these claims, for the reasons presented above and elaborated upon below.

Previous Interpretations by the EPA

This reading of the regulations comports with the EPA's statements regarding the relationship between the CAA's preconstruction and operating permit requirements at the time that the EPA initially issued the title V regulations in part 70. The EPA did not express the intention to use the title V permitting process to review the "applicable requirements" established in preconstruction permitting programs under title I of the CAA. To the contrary, the EPA stated that "[a]ny requirements established during the preconstruction review process also apply to the source for purposes of implementing title V. If the source meets the limits in its NSR permit, the title V operating permit would incorporate these limits *without further review*." Proposed Operating Permit Program, 56 Fed. Reg. 21712, 21738–39 (May 10, 1991) (emphasis added) (1991 Preamble). The EPA stated clearly that "[t]he intent of title V is not to second-guess the results of *any* State NSR program." *Id.* at 21739 (emphasis added). The EPA stated that "[d]ecisions made under the NSR and/or PSD programs (e.g., [BACT]) *define applicable SIP requirements* for the title V source and, if they are not otherwise changed, can be incorporated without further review into the operating permit for the source." *Id.* at 21721 (emphasis added).

[22] Indeed, as discussed further below, in this instance involving the BRS permit, the Petitioner invoked the state appeal process and had an opportunity for a thorough review of the propriety of the preconstruction permitting conditions for the facility through this title I process.

However, the EPA later shifted away from this understanding of part 70 (title V) permitting in circumstances where a source had already obtained a title I preconstruction permit. In title V orders and guidance documents in the late 1990s, the EPA began to interpret section (1) of the definition of "applicable requirement" to allow the EPA and states to examine the propriety of prior construction permitting decisions in the title V permitting process.

For instance, in *In the Matter of Shintech, Inc.*, Order on Petition, Permit Nos. 2466-VO, 2467-VO, 2468-VO at 3 n.2 (September 10, 1997), the EPA said:

> Where a state or local government has a SIP-approved PSD program, the merits of PSD issues can be ripe for consideration in a timely petition to object under Title V. Under 40 CFR § 70.1(b), "all sources subject to Title V must have a permit to operate that assures compliance by the source with all applicable requirements." Applicable requirements are defined in section 70.2 to include "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under Title I of the [Clean Air] Act...." The LDEQ defines "federal applicable requirement, in relevant part, to include "any standard or other requirement provided for in the Louisiana State Implementation Plan approved or promulgated by EPA through rulemaking under title I of the Clean Air Act that implements the relevant requirements of the Clean Air Act, including any revisions to that plan promulgated in 40 CFR part 52, subpart T." LAC 33:III.502. Thus, the applicable requirements of the Shintech Permits include the requirement to obtain a PSD permit *that in turn complies with the applicable PSD requirements under the Act*, EPA regulations, and the Louisiana SIP. (emphasis added)

In a 1999 letter responding to requests from permitting authorities, the Director of the Office of Air Quality Planning and Standards articulated the EPA's then-current understanding of the interaction of title I and title V. Letter from John S. Seitz, U.S. EPA, to Robert Hodanbosi, STAPPA/ALAPCO (May 20, 1999).[23] The letter stated that "applicable requirements include the requirement to obtain preconstruction permits that comply with applicable preconstruction review requirements under the Act, EPA regulations, and SIP's." *Id.* Enclosure A at 2. The letter expressed the view that section 505(b) of the Act provides a form of corrective action in addition to all the other enforcement authorities the EPA has under the Act. *Id.* While it stated that generally the agency will not object to a title V permit for determinations "made long ago[,] . . . EPA may object to [a more recent] title V permit due to an improper [preconstruction] determination." *Id.* Enclosure A at 2–3. Additionally, the letter said that the EPA could object to a title V permit where "EPA believes that an emission unit has not gone through the proper preconstruction permitting process." *Id.* Enclosure A at 3.[24] However, the letter did not provide

[23] *Available* at *https://www.epa.gov/sites/production/files/2015-08/documents/hodan7.pdf.*

[24] The EPA has also used this reading of the agency's oversight authority under title V as part of the justification for approving state PSD programs. *See* Approval and Promulgation of Implementation Plans; Oregon, 68 Fed. Reg. 2891, 2899 (January 22, 2003); *see also* Approval and Promulgation of Implementation Plans; Idaho; Designation of Areas for Air Quality Planning Purposes; Idaho, 68 Fed. Reg. 2217, 2221 (January 16, 2003). In these approvals the

any explanation for why decisions "made long ago" were entitled to more deference than recent decisions for purposes of title V permitting.

Somewhat more recently, the EPA has implicitly or explicitly assumed that preconstruction permitting decisions were ripe for review when responding to title V petitions. For instance, while not substituting its own judgment for that of a state permitting authority, the EPA has reviewed whether a petitioner demonstrated that the permitting authority's exercise of discretion under its SIP-approved regulations was unreasonable or arbitrary. *See, e.g., In the Matter of American Electric Power – John W. Turk Plant*, Order on Petition No. VI-2008-01 (December 15, 2009); *In the Matter of Cash Creek Generation*, Order on Petition Nos. IV-2008-1 & IV-2008-2 (December 15, 2009) ("Cash Creek I"); *In the Matter of Cash Creek Generation*, Order on Petition No. IV-2010-4 (June 22, 2012) ("Cash Creek II"). In these title V orders, the EPA indicated that the agency could review whether previous preconstruction permitting decisions complied with the requirements of the SIP, which would appear to be inconsistent with the preamble of the regulations in part 70 described above.

However, at the same time, the EPA has declined in the title V petition context to review the merits of PSD permits issued by the agency or by a permitting authority that has received delegation to implement the EPA's federal PSD rules. *See In the Matter of Kawaihe Cogeneration Project*, Order on Petition, Permit No. 0001-01-C (March 10, 1997). Because these permitting decisions may be appealed to the EPA's Environmental Appeals Board, the EPA has concluded that it need not entertain claims that such permits are deficient when raised in a petition to object to a title V permit.

The EPA's Approach Moving Forward

Notwithstanding the interpretation advanced with respect to title I permitting under SIP-approved programs in these previous orders and policy statements, there are many reasons to view the EPA's original interpretation of the regulations governing title V permitting, explained in the *PacifiCorp-Hunter Order*, to be more appropriate given the policy and legal reasons explained below.

First, the interpretation expressed in this Order and the *PacifiCorp-Hunter Order*—that preconstruction permit terms and conditions should be incorporated without further review—aligns with that expressed contemporaneous with the promulgation of the title V regulations in 40 C.F.R. part 70. This provides the best indication of the intention of the agency when it issued those regulations. A contemporaneous interpretation is often given great weight in understanding the meaning of a statute. *See, e.g., Good Samaritan Hosp. v. Shalala*, 508 U.S. 402, 414 (1993) ("Of particular relevance is the agency's contemporaneous construction which 'we have allowed . . . to carry the day against doubts that might exist from a reading of the bare words of a statute'" (citing *FHA v. The Darlington, Inc.*, 358 U.S. 84, 90 (1958))). Much as an agency's

---

EPA pointed to its authority under title I, sections 113 and 167, and stated that title V "has added new tools" for addressing concerns with implementation of PSD requirements by allowing for objection to title V permits under section 505(b) of the Act. However, the authority to revisit an issued preconstruction permit in the title V process does not appear to have been dispositive to the approval of these PSD programs as the EPA could still conduct oversight using its title I authorities.

contemporaneous interpretation of a statute through a regulation is given great weight, an agency's contemporaneous interpretation of its own regulations in the preamble for those regulations should carry similar weight.

More importantly, this reading—that title V permitting is not intended to second-guess the results of state preconstruction permit programs—is better aligned with the structure and purpose of title V itself. As the EPA and courts have noted on many occasions, title V was not intended to add new substantive requirements. *See, e.g.*, *United States Sugar Corp. v. EPA*, 830 F.3d 579, 597 (D.C. Cir. 2016) ("Title V does no more than consolidate 'existing air pollution requirements into a single document, the Title V permit, to facilitate compliance monitoring' without imposing new substantive requirements." (quoting *Sierra Club v. Leavitt*, 368 F.3d 1300, 1302 (11th Cir. 2004))); *United States v. Cemex, Inc.*, 864 F.Supp.2d 1040, 1045 (D. Colo. 2012) ("'Title V permits do not generally impose any new emission limits, but are intended to incorporate into a single document all of the Clean Air Act requirements applicable to a particular facility' and to provide for monitoring and other compliance measures." (quoting *United States v. EME Homer City Generation L.P.*, 823 F.Supp.2d 274, 283 (W.D. Pa. 2011))).

Title V contains no language that says that this consolidation process[25] must involve a review of the substantive adequacy of any "applicable requirements" or a reconsideration of whether the "applicable requirements" were properly derived. This would entail much more than taking steps to "consolidate 'existing air pollution requirements.'" *United States Sugar Corp. v. EPA*, 830 F.3d at 597. As the courts have acknowledged, the purpose of the title V program is to identify which of the myriad of requirements under the CAA are applicable to an individual source. These include many requirements that are broadly applicable to entire categories of sources or sources with particular characteristics. In this case, the preconstruction requirements under the Act are different than many of these other requirements in that they were derived on a case-by-case basis in a source-specific process that produced permit terms and conditions that are expressly applicable to an individual source. But the Act does not say that "applicable requirements" with these characteristics must be checked in the title V process to determine if they were properly derived before they can be consolidated into an operating permit. Neither does the Act demand that these "applicable requirements" be re-checked each time the operating permit is renewed.

Before title V of the CAA was enacted, Congress enacted the title I preconstruction permitting requirements in the 1977 Amendments to the CAA. At that time, Congress understood that the adequacy of state preconstruction permitting decisions would be subject to review in state administrative and judicial forums.[26] Congress has also given the EPA specific oversight authority under title I to, among other authorities, approve or disapprove state permitting

---

[25] While the preconstruction permit conditions applicable to BRS were not consolidated into the title V permit at a later date in this instance because the PSD and title V processes occurred concurrently, as explained above, the EPA does not view a concurrent process undertaken for administrative efficiency as expanding the scope of EPA's review in the title V context.

[26] "In order to challenge the legality of a permit which a State has actually issued ... a citizen must seek administrative remedies under the State permit consideration process, or judicial review of the permit in State court." Staff of the Subcommittee on Environmental Pollution of the Senate Committee on Environment and Public Works, 95th Congress, 1st Session, A Section-by-section Analysis of S. 252 and S. 253, Clean Air Act Amendments 36 (1977), reprinted in 5 Legislative History of the Clean Air Act Amendments of 1977 3892 (1977).

programs, 42 U.S.C. § 7410(a)(2)(C), call for revisions to those programs, *id.* § 7410(k)(5), issue injunctive orders to halt construction, *id.* § 7477, and pursue various types of enforcement actions pursuant to sections 113 and 167 of the Act, *id.* § 7413, § 7477.

There is no clear indication in the terms of the 1990 Amendments to the CAA or its legislative history that the addition of the title V provisions to the Act was intended to add another opportunity to review the merits of a construction permitting decision in addition to the title I authorities that existed already or that were added as part of the 1990 Amendments. There is no clear indication that Congress intended to alter the balance of oversight that the EPA had over state preconstruction permitting through title V review. Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001). A reading of part 70 that would transform title V into an opportunity to reevaluate previous preconstruction approvals, instead of simply incorporating existing air pollution requirements into one document, would "alter the fundamental details" of the oversight authorities the EPA has under title I of the Act. For instance, instead of disapproving the preconstruction requirements in a state SIP or issuing a stop construction order to an individual source, which Congress explicitly authorized, the EPA could issue administrative orders on a case-by-case basis under title V. The text of the Act does not indicate that Congress intended to create this type of additional administrative oversight mechanism for preconstruction permitting actions in an operating permit program designed to consolidate and make existing requirements enforceable. While there is language in title V requiring that a permit "assure compliance with applicable requirements of this chapter," *e.g.*, 42 U.S.C. § 7661c(a), and similarly broad language in other parts of title V, this type of general language does not clearly or specifically say that a title V permitting authority must reevaluate preconstruction permitting decisions that have already been made under title I each time that it issues or renews a title V permit. Consistent with the EPA's contemporaneous interpretation of its part 70 regulations, this general language in the statute should be read to mean that the title V permit must include conditions to ensure compliance with the terms and conditions of the source-specific preconstruction permits that have been issued for the source. Absent language providing a clearer or direct indication that the provisions in title V of the Act require the reevaluation of preconstruction permitting decisions for a source, the EPA is determining that it should not read general and broad terms to find such a preconstruction permitting oversight tool "hidden" in the title V permitting program.

The EPA's preconstruction permitting oversight authority under title I of the Act supports reading the title V provision to supply a more limited oversight role for the EPA with regard to state implementation of preconstruction permitting programs.[27] The EPA believes that its oversight of case-specific state title I permitting decisions should be handled under title I, such as through comments on state permits or an order or action under section 113 or section 167 of the CAA. Citizen oversight may still be accomplished through either the state appeal process[28] or

[27] *See* 42 U.S.C. § 7401(a)(3) ("The Congress finds . . . air pollution control at its source is the primary responsibility of States and local governments.")

[28] Indeed, as discussed further below, in this instance involving the BRS permit, the Petitioner invoked the state appeal process and had an opportunity for a thorough review of the propriety of the preconstruction permitting conditions for the facility through this process.

through a citizen suit under section 304, depending on the type of issues involved. As described in this Order, for purposes of title V, the permitting authority should incorporate the terms and conditions of preconstruction permits into the source's title V permit, unless and until those preconstruction permits are revised, reopened, suspended, revoked, reissued, terminated, augmented, or invalidated through one of these mechanisms.[29] Similarly, broader programmatic issues should be handled under the EPA's existing title I authorities instead of through case-by-case objections under title V.

Other provisions of title V support the interpretation in this Order. For instance, title V requires state programs to have "[a]dequate, streamlined, and reasonable procedures . . . for expeditious review of permit actions . . ." 42 U.S.C. § 7661a(b)(6). Requiring the EPA to go back and review final preconstruction permitting decisions that have already been subject to the safeguards of public notice and judicial review could frustrate the goal of "expeditious review of permit action." While the preconstruction and operating permits in this case were processed concurrently, as noted above, that is not a requirement of part 70 or title V.

Similarly, Congress also provided abbreviated timeframes for the EPA to review a proposed title V permit: 45 days for the EPA's independent review, and 60 days if confronted with a petition to object. 42 U.S.C. § 7661d(b). These timeframes are inconsistent with an in-depth and searching review of the type of source-specific preconstruction permitting decisions that are made by the permitting authority under title I. Instead, these provisions suggest that the EPA's role in oversight over the issuance of title V permits should be limited. The Administrator will object to a title V permit if it does not include the "applicable requirements" or does not otherwise comply with part 70. 40 C.F.R. § 70.8(c). The EPA's oversight ensures that the permitting authority has properly included the "applicable requirements" as they apply to the source and followed the requirements of title V by including adequate monitoring, recordkeeping, and reporting to assure compliance with those requirements.[30] *See* 42 U.S.C. § 7661c(a), 7661c(c); 40 C.F.R. § 70.6(a)(3), 70.6(c)(1). In the case of preconstruction permitting requirements derived under title I of the Act, the EPA's oversight role under title V is to ensure that the terms and conditions derived under title I are properly included in the title V permit as "applicable requirements," and that the title V permit contains monitoring, recordkeeping, and reporting sufficient to assure compliance with those permit terms and conditions.

---

[29] In this way, this interpretation is consistent with the EPA's statements in *In the Matter of Midwest Generation-Joliet Generating Station and Will County Generating Station*, Order on Petition No. V-2005-2 (June 14, 2007). *See supra* note 24 and accompanying text.

[30] For instance, in a case where a PSD permit is issued prior to a title V permit, the EPA would review whether the title V permit includes all the terms and conditions of the preconstruction permit and whether they appear as they appear in the preconstruction permit. If terms or conditions are left out, then the title V permit does not include all the applicable requirements, i.e., the terms and conditions of the preconstruction permit. In the instant case, because the title V permit and preconstruction permit are combined in one permit document, it is clear that the title V permit includes all the terms and conditions of the preconstruction permit (there is no separate document containing the PSD conditions). The EPA's review of the title V permit will still consider whether the permit has adequate monitoring, recordkeeping, and reporting to assure compliance with all applicable requirements, including the preconstruction permit requirements.

The EPA believes that it is inefficient and inappropriate for the EPA to review as part of the title V permitting process the preconstruction permitting decisions that are subject to public notice and comment and an opportunity for judicial review, even in "merged" or "one permit" programs. Here, in the case of the BRS Permit, the public had the opportunity to challenge the PSD conditions issued by ADEQ through the appropriate channels of state administrative and judicial review, and in fact the Petitioner took advantage of this opportunity. Following public notice of the Permit, the Petitioner submitted comments to ADEQ related to the issues raised in the title V Petition. After ADEQ issued the Permit, the Petitioner then challenged the majority of the PSD-related issues discussed above through an extensive adjudicatory process before the APC&EC's Administrative Hearing Officer, as provided by APC&EC Regulation 8.214 and Regulation 8 Chapter 6. This process involved discovery[31] and an evidentiary hearing, and culminated in a recommendation that the APC&EC affirm the Permit. *See In the Matter of: Big River Steel, LLC*, Permit No. 2305-AOP-R0, APC&EC Docket No. 13-0060P. Subsequent to the APC&EC's affirmation of the Permit, the Petitioner obtained judicial review of the Permit in the Court of Appeals of Arkansas, pursuant to APC&EC Regulation 8.217 and Regulation 8 Chapter 7. That court, too, affirmed the permit. *Nucor Steel-Arkansas v. APC&EC*, 478 S.W.3d 232 (Ark. Ct. App. December 9, 2015). Thus, the Petitioner had ample opportunity to challenge the various PSD determinations summarized above, of which it in fact took full advantage. The Petitioner's appeal of the preconstruction permitting decisions through the title I appeal process was the proper process under the CAA to obtain review of these decisions. The Petitioner is now, in essence, asking for a "second bite at the apple" through EPA oversight in the title V process. The availability of notice, opportunity to comment, and ability to seek judicial review on ADEQ's PSD determinations weigh heavily against the title V process being an additional avenue to evaluate these preconstruction permitting decisions.

Additionally, the availability of these title I avenues to address concerns with preconstruction permitting decisions illustrates how the title V permitting process and the EPA's oversight of state title V permits are ill-suited forums for considering these issues. As noted above, the EPA only has 45 days and 60 days to review a title V permit and any subsequent petition to object, respectively. Given the complex technical review required and the amount of documentation to review in order to evaluate the derivation of the substantive requirements of a preconstruction permit, this timeframe is often inadequate to fully consider the issues presented. A state adjudicatory process allows more time for development and consideration of the potential issues raised in a state's application of preconstruction permitting requirements to this particular source—another indication that these state processes and mechanisms are the appropriate forum for citizens to raise these types of preconstruction permitting issues.

---

[31] Where discovery is available under state administrative and judicial review procedures, this can involve the review of a significant amount of documentation concerning preconstruction permitting decisions. While the EPA does not rely on the factual assertions made by the Petitioner in the Supplemental Petition, the present case is illustrative of this point: the Petitioner suggests in the Supplemental Petition that discovery in the administrative appeal of the BRS Permit involved over 200,000 pages of documents. In some administrative and judicial appeal processes, review of a permitting decision is based on an administrative record established at the time of the decision under review, and there is no opportunity for discovery or testimony to add to the administrative record. Such an administrative record on a preconstruction permit decision can be voluminous even without discovery or witness testimony. Under either type of review, the documentation from the preconstruction permitting may or may not be included in the title V permitting record depending on the particular situation.

The interpretation of the title V rules and statutory provisions reflected in this Order also aligns the EPA's treatment of preconstruction permits with how the EPA has consistently treated other "applicable requirements" under title V. For many other "applicable requirements," permitting agencies do not reconsider the content of those requirements in title V permits, nor does the EPA in its oversight role of title V permitting. For instance, the EPA would not allow a permitting authority to revise the substantive requirements of New Source Performance Standards established under section 111, or National Emission Standards for Hazardous Air Pollutants established under section 112.[32] These substantive requirements have already been established pursuant to a process that included public notice and comment and the opportunity for judicial review. It would therefore be inappropriate to reevaluate these standards in title V permitting. Likewise, source-specific preconstruction permitting that has been put out for notice and comment and the opportunity for judicial review has gone through a similar process at the state level. For purposes of title V permitting, it makes sense to treat decisions that go through similar processes similarly.

The EPA has also declined to second-guess the content of "applicable requirements" even when a title V permit incorporates SIP provisions that the EPA has determined are inconsistent with the CAA. The EPA has said that the proper forum to address whether a SIP provision is inconsistent with the CAA is through a "SIP Call" under CAA section 110(k). *In the Matter of Piedmont Green Power*, Order on Petition Number IV-2015-2 at 28–29 (December 13, 2016) (*Piedmont Green Power Order*); *see In the Matter of Midwest Generation, LLC, Joliet Generating Station*, Order On Petition No. V-2004-5 at 17, 20–21, 23–24 (June 24, 2005) ("[A] permitting authority cannot use a title V permit to modify a requirement from a federally approved SIP.").[33] Until the EPA approves a corrective SIP revision or issues a Federal Implementation Plan (FIP), no action within the title V permits is required. *Piedmont Green Power Order* at 29. Even if the EPA has concluded that the SIP provision is inconsistent with the Act, the title V permit should continue to incorporate the SIP provision because it is an "applicable requirement." Similarly, a decision by the EPA not to object to a title V permit that includes the terms and conditions of a title I permit does not indicate that the EPA has concluded that those terms and conditions comply with the applicable SIP or the CAA. However, until the terms and conditions of the title I permit are revised, reopened, suspended, revoked, reissued, terminated, augmented, or invalidated through some other mechanism, such as a state court appeal, the "applicable requirement" remains the terms and conditions of the issued preconstruction permit and they should be included in the source's title V permit. Consistent with 40 C.F.R. part 70, this Order treats the reviewability of preconstruction permitting conditions established by the permitting authority in a manner similar to the requirements of the SIP for purposes of title V permitting.

---

[32] As noted above, the permitting authority may use the title V process to consider enhancing the monitoring, recordkeeping, or reporting required to assure compliance with these standards. *See, e.g., In the Matter of Wheelabrator Baltimore*, Order on Petition, Permit No. 24-510-01886 at 11–13 (April 14, 2010).

[33] See also; *In the Matter of Monroe Power Company*, Order on Petition IV-2001-8 at 14 (October 9, 2002); *In the Matter of Pacificorp's Jim Bridger and Naughton Electric Utility Steam Generating Plants*, Order on Petition No. VIII-00-1 at 23-24 (November 16, 2000).

For these reasons, the interpretation in this Order of title V and part 70 (and embodied in the 1991 Preamble) more closely aligns with the intent and purpose of title V than the departure from that interpretation expressed in certain previous orders and other agency statements, as discussed above. Consistent with this reading, permitting agencies and the EPA need not evaluate—in the context of title V permitting, oversight, or petition responses—the preconstruction permit terms and conditions under title I of the Act. That is especially so in a case such as this one involving the BRS permit where the title I preconstruction requirements have already been the subject of an extensive administrative appeal and a judicial review in the state system. Citizen concerns with these preconstruction permit conditions should be handled under the authorities found in title I of the Act. The permit terms and conditions derived under title I of the Act[34] should be incorporated as "applicable requirements" and the permitting authority and the EPA should limit its review under the procedures that are unique to title V permits to whether the title V permit has accurately incorporated those terms and conditions and whether the title V permit includes adequate monitoring, recordkeeping, and reporting requirements to assure compliance with the terms and conditions of the preconstruction permit. *See* 42 U.S.C. § 7661c(a); 40 C.F.R. § 70.6(a)(3), 70.6(c)(1).

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on these claims.

Claim C.4: The Petitioner's Claim that "The Permit does not contain enforceable permit conditions that lead to compliance."

Petitioner's Claim: In Claim C.4, the Petitioner challenges permit conditions related to two dust control plans, which the Petitioner contends "[t]he Permit prominently relies upon." Petition at 29 (citing Permit Specific Conditions 95, 100, and 108). The Petitioner asserts that it previously commented that "the permit should specify when the dust control plan must be prepared and should list the minimum required Plan elements or criteria." *Id.* at 30. The Petitioner claims that ADEQ's response was inadequate, asserting that "the permit does not list any minimum plan elements or criteria." *Id.*

The Petitioner alleges that the permit contains a requirement to record water and materials throughput data, but argues that "the mere keeping of data does not demonstrate that the emissions are well controlled," which the Petitioner asserts would require "that the water be applied at a certain rate or when needed." *Id.* The Petitioner asserts that there is no explanation of how this monitoring and recordkeeping requirement will maintain proper controls. *Id.*

The Petitioner argues that the EPA previously "held that a title V permitting agency must include in the public record for review any element required to determine compliance with the conditions of the permit." *Id.* at 30 (citing *In the Matter of Alliant Energy, WPL Edgewater Generating Station*, Order on Petition No. V-2009-02 (August 1, 2010) (*Alliant Edgewater Order*)). Further, the Petitioner asserts that "the permitting authority must explain how the proposed monitoring

[34] This Petition only regards an issued major source PSD permit. However, the EPA has previously applied a similar interpretation and reasoning in denying a petition when the source had been issued a minor NSR permit. *See PacifiCorp-Hunter Order* at 8–20.

will lead to compliance" (citing *Alliant Edgewater Order*) and claims that "ADEQ has failed to do this." *Id.*

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

The Petitioner asserts that it previously commented to ADEQ that "the permit should list the minimum required plan elements for these dust control plans," and that "the permit does not list any minimum plan elements or criteria." Petition at 29–30. However, the Petitioner has not cited any legal authority for this claim.[35] The Petitioner implies that the Permit's lack of minimum required plan elements results in the Permit not assuring compliance with applicable requirements, as the Petitioner claims that "the permitting authority must explain how the proposed monitoring will lead to compliance." Petition at 30.[36] However, the Petitioner has failed to demonstrate that the dust control plans are required to determine compliance with any permit conditions or any applicable requirement. The Petitioner asserts that the Permit "prominently relies upon" the dust control plans, citing without further explanation Specific Conditions 95, 100, and 108, Petition at 29, but the Petition lacks any discussion of the relationship between the dust control plans and the cited permit conditions or any applicable requirement to which such plans might relate. As the EPA has repeatedly stated, general assertions are insufficient to demonstrate that a permit is not in compliance or does not assure compliance with applicable requirements.[37] The EPA expects a petitioner to clearly explain, with citation and analysis, why a particular permit term does not comply with, or assure compliance with, a specific applicable requirement.[38] Moreover, the Petitioner has not addressed—and therefore has not demonstrated—why any particular potential elements of a dust control plan, either alone or in conjunction with other control technology required by the permit, are necessary to assure compliance with any permit terms.[39] Accordingly, the Petitioner has not demonstrated that the relevant Permit requirements, viewed together, are inadequate to assure compliance with any applicable requirement.

---

[35] The EPA notes that the Petitioner simply claimed that the permit should list minimum required plan elements or criteria. The Petitioner did not claim in the Petition—and accordingly, did not demonstrate—that either of the fugitive dust control plans were required by any particular applicable requirement. Nor did the Petitioner claim or demonstrate that the plans themselves were required to be included in the Permit, nor demonstrate that they were required to be available for public review as part of the permit application. *See In the Matter of Louisiana Pacific Corporation*, Order on Petition No. V-2006-3 at 15–16 (November 5, 2007) ("The Fugitive Dust Control Plan is not an applicable SIP requirement; therefore it was not necessary for WDNR to make it available as part of the permit record during the public comment period."); *Kentucky Syngas Order* at 12 ("In this case, the Petitioners did not demonstrate that the flare monitoring plan required by KSG's permit is relied upon to impose an applicable requirement or as a compliance assurance measure.").

[36] The Petitioner also asserts that the EPA in the *Alliant Edgewater Order* held that "a title V permitting agency must include in the public record for review any element required to determine compliance with the conditions of the permit." The Petitioner did not further develop a claim based on this reference to the *Alliant Edgewater Order*, and, as discussed below, the Petitioner has not demonstrated that specifying the minimum required elements of the dust control plans is necessary to determine compliance with the conditions of the permit.

[37] *See supra* note 7 and accompanying text.

[38] *See supra* note 6 and accompanying text.

[39] For example, although the Petitioner alleges that water must be applied "at a certain rate or when needed" in order to adequately control emissions, the Petitioner provides no justification for this assertion, nor does the Petitioner explain why this is necessarily true for any of the particular emission points listed in Specific Condition 95.

Regarding the Petitioner's brief claim that "[t]he permit simply lists a requirement to record throughput data (for water and materials), but the mere keeping of data does not demonstrate that the emissions are well controlled," Petition at 30, the Petitioner appears to challenge the sufficiency of certain permit conditions related to compliance assurance.[40] As an initial matter, the EPA need not consider the Petitioner's apparent challenge to these compliance assurance conditions because these claims were not raised with reasonable specificity during the public comment period,[41] and the Petitioner has not demonstrated that it was impractical to do so. 42 U.S.C. § 7661d(b)(2). Even if considered, the Petitioner's characterization of the permit is incomplete and therefore incorrect. While Specific Condition 97 and Plantwide Condition 5 include throughput recordkeeping conditions, Specific Condition 96 additionally establishes legally enforceable throughput limits on the materials received by various emission sources. The Petition fails to mention the limits contained in Specific Condition 96, which are clearly a key element of how BRS will be required to restrict emissions from these units in order to comply with relevant permit conditions. As the EPA has previously indicated, the failure to acknowledge a key permit condition relevant to the issues raised in the petition supports the EPA's determination that a petitioner has failed to demonstrate a flaw in the permit. *See, e.g., Homer City Order* at 48. Moreover, the Petitioner has provided no information explaining how these compliance assurance conditions are related to the dust control plans at issue in the Petition.

To the extent that the dust control plans are a part of the set of controls and limits that ADEQ determined constitute BACT for the source under the title I PSD program requirements, the EPA will not, in this Order, evaluate the sufficiency of such a BACT determination, for the reasons described in the EPA's response to the claims related to PSD determinations above.[42]

Overall, the Petitioner has not demonstrated, with respect to the dust control plans required by the Permit, that the Permit omits any applicable requirement or that the Permit fails to assure compliance with any applicable requirement.

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

Claim C.5: The Petitioner's Claim that "The Permit does not contain adequate monitoring, recordkeeping and reporting requirements to comply with the requirements of 40 C.F.R. 70.6(a)(3)(i)(B) because it does not provide for a test method."

---

[40] Although the Petitioner does not expressly cite Specific Condition 96, Specific Condition 97, or Plantwide Condition 5, the Petitioner's claim may be referring to these conditions. *See* Permit at 111, Specific Condition 95 ("Compliance with this condition will be show[n] by compliance with Specific Conditions 96 and 97 and Plantwide Condition 5.").

[41] The public comments on this point simply stated: "Miscellaneous Operations, SC 95 and Roadway Sources SC 103. These conditions refer to the Control Technology as a 'Dust Control Plan.' However, there is no Condition requiring development and/or submittal of this Plan (SC 103 refers to the dust control plan for roadways, but not raw material handling operations). In order to be enforceable, the permit should specify when the dust control plan must be prepared and should list the minimum required Plan elements or criteria." Petition Attachment 1, Nucor Comment No. 40.

[42] *See supra* pp. 8–20.

Petitioner's Claim: In Claim C.5, the Petitioner claims that Specific Condition 93, which concerns the testing of total dissolved solids (TDS) in the cooling towers, is inadequate because the Permit does not specify the TDS test method. Petition at 30.

The Petitioner asserts that, in response to a comment, ADEQ updated Specific Condition 93 "to state that [TDS] testing can be conducted by a method approved by [ADEQ] prior to testing." *Id.* at 30–31. The Petitioner further asserts that "it is clear that the method of determining TDS is critical to determining whether the BRS will be in long term compliance" and that "it is impossible to determine from the record how compliance is to be determined" because ADEQ's response postpones resolution of this issue to beyond the title V permitting process. *Id.* at 31. The Petitioner argues that ADEQ can neither "defer critical decisions" to beyond the permitting period, nor refuse to provide public notice and an opportunity to comment on "critical monitoring provisions." *Id.* at 31 (citing *Alliant Edgewater Order*). The Petitioner argues further that "permitting authorities do not have the discretion to issue a permit without specifying the monitoring methodology needed to assure compliance with applicable requirements in the title V permit." *Id.* at 31 (quoting *In the Matter of United States Steel Corporation – Granite City Works*, Order on Petition No. V-2011-2 (December 3, 2012), which in turn quoted *In the Matter of Wheelabrator Baltimore*, Order on Petition, Permit No. 24-510-01886 at 10 (April 14, 2010)). The Petitioner claims that this problem is compounded because the permit does not specify the units in which TDS is to be determined. *Id.* at 31.

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

The Permit, in Specific Condition 93, requires BRS to "test the TDS of each of the cooling towers initially and every 6 months thereafter. This testing shall be conducted in accordance with Plantwide Condition 3 with a method approved by the Department before the first test is performed." Permit at 108. The Petitioner notes that Specific Condition 93 does not specify a particular TDS test method, and claims that the Permit must do so. However, as discussed below, the Petitioner has not demonstrated that a TDS test method must be specified in the Permit in order to assure compliance with any applicable requirement.

The Petitioner asserts that "it is clear that the method of determining TDS is critical to determining whether the BRS [facility] will be in long term compliance." Petition at 31. As an initial matter, the Petitioner does not identify any permit terms or applicable requirements for which specifying the TDS test method in the Permit is "critical"; the Petition lacks any discussion concerning how the selection of a TDS test method is related to any particular requirement. Although not described in the Petition, the EPA notes that the TDS testing required by Specific Condition 93 is expressly identified as the compliance demonstration methodology for Specific Conditions 91 and 92, and, by extension, for Specific Condition 90—all of which are associated with PM emissions from the cooling towers.[43] Specific Condition 93, as noted above,

---

[43] Specific Condition 90 contains PM, PM_{10}, and $PM_{2.5}$ emission limits, in units of pounds per hour and tons per year, for the facility's 12 cooling towers. This condition states that "[t]he permittee shall demonstrate compliance with this condition by compliance with Specific Conditions 92 and 91." Permit at 106. Specific Condition 91 contains a BACT Analysis Summary and imposes a BACT limit, i.e., a 0.0005 percent drift loss limit for each of the

requires that "[t]he permittee test the TDS of each of the cooling towers initially and every 6 months thereafter." Permit at 108. Thus, contrary to the Petitioner's assertion that "it is impossible to determine from the record how compliance is to be determined," Petition at 31, the Permit clearly states the method by which compliance with relevant permit conditions will be determined—by testing TDS concentrations initially and every six months.

Contrary to the Petitioner's unsupported assertion that "it is clear that the method of determining TDS is critical," Petition at 31, it is unclear from the abbreviated information on this claim in the Petition *why* specifying a TDS test method is "an essential part of the monitoring requirements." *Wheelabrator Order* at 11. The Petitioner has not claimed that any particular TDS test method would be more or less reliable or accurate than another available method, or even whether multiple TDS test methods exist, nor how any potential differences between such test methods would materially affect a demonstration of compliance.

Overall, the Permit specifies the method by which BRS will demonstrate compliance with relevant permit conditions—by testing TDS concentrations every six months. The Petitioner has not demonstrated that additional information concerning the exact protocol or method by which the TDS testing will be conducted must be included in the permit. The Petitioner's general allegations—unsupported by any technical explanation or justification or consideration of the specific relationship between TDS testing and the relevant requirements with which it assures compliance—fail to demonstrate that the method of determining TDS is "an essential part of the monitoring requirements that must be in the title V permit to assure compliance" with relevant permit terms. *Wheelabrator Order* at 11. Because the Petitioner has not demonstrated why the specific TDS test method is "essential" to assuring compliance with any applicable requirement, the Petitioner has not demonstrated that the permit does not "specify[] the monitoring methodology *needed to assure compliance* with applicable requirements in the title V permit," as the EPA directed in the *U.S. Steel Order* (emphasis added),[44] or that the public was deprived of the "opportunity to comment on critical monitoring provisions." Petition at 31.

---

12 cooling towers, based on the installation of drift eliminators as an emission control device and the implementation of low TDS solids in the cooling water as a pollution prevention measure, as well as a 5 percent opacity limitation. This condition states further that "[c]ompliance with this condition will be show[n] by compliance with Specific Conditions 92 and 93." *Id.* at 107. Specific Condition 92, which imposes numerical TDS limits on various cooling towers, in turn states that "[t]he permittee shall demonstrate compliance with this condition by compliance with Specific Condition 93." *Id.*

[44] The EPA notes that the title V petition orders that the Petitioner briefly quotes (the *U.S. Steel Order* and the *Wheelabrator Order*) involved monitoring provisions that were "needed to assure compliance," *U.S. Steel Order* at 10, or "an essential part of the monitoring requirements," *Wheelabrator Order* at 11. The Petitioner has the burden of providing sufficient legal and factual analysis to demonstrate that the EPA should object to a title V permit. The Petitioner has failed to provide that analysis and has therefore not made such a demonstration. Aside from quoting from a single sentence in those orders, the Petitioner has not provided any analysis explaining why the facts in those cases are sufficiently similar to those alleged in the Petition such that an objection to the monitoring conditions in the Permit is warranted. The EPA notes that claims in both the *U.S. Steel* and *Wheelabrator Orders* involved different types of monitoring provisions than the one at issue in the BRS Petition; each involved claims regarding essential pieces of the overall monitoring methodology. The U.S. Steel permit did not specify any emission factors or equations necessary to determine emissions. *See U.S. Steel Order* at 11–12. The Wheelabrator permit did not specify which parameters would be monitored in order to convert continuous emission monitoring systems data into mass emissions data. *See Wheelabrator Order* at 11. By failing to provide any analysis, the Petitioner has not demonstrated that the TDS test method is a similar critical piece of the overall monitoring methodology. Notably,

Regarding the Petitioner's brief statement in passing that the permit does not specify the units in which TDS is to be determined, this assertion, even if considered a claim, was not raised with reasonable specificity during the public comment period. Moreover, the EPA notes that the permit application clearly indicates that the units are in milligrams per liter or parts per million (equivalent units in this application), as is standard for quantifying TDS.[45] The Petitioner has not demonstrated that the absence of this information on the face of the Permit resulted in a flaw in the permit.

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

V. CONCLUSION

For the reasons set forth above and pursuant to CAA § 505(b)(2) and 40 C.F.R. § 70.8(d), I hereby deny the Petition as described above.

Dated: OCT 31 2017

Scott Pruitt

E. Scott Pruitt,
Administrator.

---

neither the *U.S. Steel Order* nor the *Wheelabrator Order* implicated the question of whether a test method or sampling protocol (for TDS or any other parameter or limit) must be specified in a permit. In contrast, in the *Kentucky Syngas Order*, the EPA denied a similar claim related to a sulfur content test protocol that was not contained in the permit, noting:

> The 'plan' referenced here appears to be essentially a performance test protocol. This point is explained by KDAQ as follows, "[t]he development of a sampling plan for the AGR vent prior to initial startup is no different than developing and submitting a performance test protocol prior to conducting the test. Permit conditions which allow developing and submitting a performance test protocol prior to conducting the test are common and contained in many permits approved by the EPA."

Kentucky Syngas Order at 13.

[45] *See* Petition Attachment 5, Final Air Permit Application, Vol. 2 at 163–66 (June 21, 2013).

To: Santiago, Juan[Santiago.Juan@epa.gov]; Vetter, Cheryl[Vetter.Cheryl@epa.gov]; Spangler, Matthew[Spangler.Matthew@epa.gov]
Cc: Johnson, Yvonne W[Johnson.Yvonnew@epa.gov]; Mataway-Novak, Dylan[Mataway-Novak.Dylan@epa.gov]; Keller, Peter[keller.peter@epa.gov]
From: Long, Pam
Sent: Tue 10/17/2017 12:55:54 PM
Subject: Signed PacificCorp Hunter Title V Petition
PacifiCorp Hunter ORDER 10-10-17 clean.docx
Signed PacifiCorp Hunter 10-16-17.pdf

Signed and word file.

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF PACIFICORP ENERGY HUNTER POWER PLANT EMERY COUNTY, UTAH PERMIT NO. 1500101002 ISSUED BY THE UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY, DIVISION OF AIR QUALITY	PETITION NO. VIII-2016-4 ORDER RESPONDING TO PETITION REQUESTING OBJECTION TO THE ISSUANCE OF A TITLE V OPERATING PERMIT

ORDER DENYING A PETITION FOR OBJECTION TO PERMIT

I. INTRODUCTION

The U.S. Environmental Protection Agency (EPA) received a petition dated April 11, 2016 (the Petition) from Sierra Club (the Petitioner), pursuant to section 505(b)(2) of the Clean Air Act (CAA or Act), 42 U.S.C. § 7661d(b)(2). The Petition requests that the EPA object to the operating permit no. 1500101002 (2016 Permit) issued by the Utah Department of Environmental Quality, Division of Air Quality (UDAQ) to PacifiCorp Energy for the Hunter Power Plant (PacifiCorp-Hunter or the facility) in Castle Dale, Emery County, Utah. The operating permit was proposed pursuant to title V of the CAA, CAA §§ 501–507, 42 U.S.C. §§ 7661–7661f, and Utah Admin. Code R307-415. *See also* 40 C.F.R. part 70 (title V implementing regulations). This type of operating permit is also referred to as a title V permit or part 70 permit.

Based on a review of the Petition and other relevant materials, including the 2016 Permit, the permit record, and relevant statutory and regulatory authorities, and as explained further below, the EPA denies the Petition requesting that the EPA object to the 2016 Permit.

II. STATUTORY AND REGULATORY FRAMEWORK

A. Title V Permits

Section 502(d)(l) of the CAA, 42 U.S.C. § 766la(d)(1), requires each state to develop and submit to the EPA an operating permit program to meet the requirements of title V of the CAA and the EPA's implementing regulations at 40 C.F.R. part 70. The state of Utah submitted a title V program governing the issuance of operating permits on April 14, 1994. The EPA granted full approval of Utah's title V operating permit program in 1995. 60 Fed. Reg. 30192 (June 8, 1995).

This program, which became effective on July 10, 1995, is currently codified in Utah Admin. Code R307-415.[1]

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable implementation plan. CAA §§ 502(a), 504(a), 42 U.S.C. §§ 7661a(a), 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements, but does require permits to contain adequate monitoring, recordkeeping, reporting, and other requirements to assure sources' compliance with applicable requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992); *see* CAA § 504(c), 42 U.S.C. § 7661c(c). One purpose of the title V program is to "enable the source, States, the EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." 57 Fed. Reg. at 32251. Thus, the title V operating permit program is a vehicle for compiling the air quality control requirements as they apply to the facility's emission units and for providing adequate monitoring, recordkeeping, and reporting to assure compliance with such requirements.

B. Review of Issues in a Petition

State and local permitting authorities issue title V permits pursuant to their EPA-approved title V programs. Under CAA § 505(a), 42 U.S.C. § 7661d(a), and the relevant implementing regulations found at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to the EPA for review. Upon receipt of a proposed permit, the EPA has 45 days to object to final issuance of the proposed permit if the EPA determines that the proposed permit is not in compliance with applicable requirements under the Act. CAA § 505(b)(1), 42 U.S.C. § 7661d(b)(1); *see also* 40 C.F.R. § 70.8(c). If the EPA does not object to a permit on its own initiative, any person may petition the Administrator, within 60 days of the expiration of the EPA's 45-day review period, to object to the permit. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d).

The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting authority (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d)). In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. CAA § 505(b)(2), 42 U.S.C.

[1] The Utah operating permit program regulations that were approved by the EPA were originally codified in Utah Admin. Code R307-15. These regulations were subsequently re-numbered to R307-415. The Petition refers to the relevant provisions of the Utah Administrative Code as the Utah Air Conservation Regulations or Utah Air Conservation Rules (UACR). Both the Utah Administrative Code and UACR section numbers and content are identical.

§ 7661d(b)(2); 40 C.F.R. § 70.8(c)(1).[2] Under section 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to the EPA.[3]

The petitioner's demonstration burden is a critical component of CAA § 505(b)(2). As courts have recognized, CAA § 505(b)(2) contains both a "discretionary component," to determine whether a petition demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act, and a nondiscretionary duty to object where such a demonstration is made. *Sierra Club v. Johnson*, 541 F.3d at 1265–66 ("[I]t is undeniable [that CAA § 505(b)(2)] also contains a discretionary component: it requires the Administrator to make a judgment of whether a petition demonstrates a permit does not comply with clean air requirements."); *NYPIRG*, 321 F.3d at 333. Courts have also made clear that the Administrator is only obligated to grant a petition to object under CAA § 505(b)(2) if the Administrator determines that the petitioner has demonstrated that the permit is not in compliance with requirements of the Act. *Citizens Against Ruining the Environment*, 535 F.3d at 677 (stating that § 505(b)(2) "clearly obligates the Administrator to (1) determine whether the petition demonstrates noncompliance and (2) object *if* such a demonstration is made" (emphasis added)).[4] When courts have reviewed the EPA's interpretation of the ambiguous term "demonstrates" and its determination as to whether the demonstration has been made, they have applied a deferential standard of review. *See, e.g.*, *MacClarence*, 596 F.3d at 1130–31.[5] Certain aspects of the petitioner's demonstration burden are discussed below; however, a more detailed discussion can be found in *In the Matter of Consolidated Environmental Management, Inc., Nucor Steel Louisiana*, Order on Petition Nos. VI-2011-06 and VI-2012-07 at 4–7 (June 19, 2013) *(Nucor II Order)*.

The EPA has looked at a number of criteria in determining whether a petitioner has demonstrated noncompliance with the Act. *See generally Nucor II Order* at 7. For example, one such criterion is whether the petitioner has addressed the state or local permitting authority's decision and reasoning. The EPA expects the petitioner to address the permitting authority's final decision, and the permitting authority's final reasoning (including the state's response to comments), where these documents were available during the timeframe for filing the petition. *See MacClarence*, 596 F.3d at 1132–33.[6] Another factor the EPA has examined is whether a

---

[2] *See also New York Public Interest Research Group, Inc. v. Whitman*, 321 F.3d 316, 333 n.11 (2d Cir. 2003) *(NYPIRG)*.

[3] *WildEarth Guardians v. EPA*, 728 F.3d 1075, 1081–82 (10th Cir. 2013); *MacClarence v. EPA*, 596 F.3d 1123, 1130–33 (9th Cir. 2010); *Sierra Club v. EPA*, 557 F.3d 401, 405–07 (6th Cir. 2009); *Sierra Club v. Johnson*, 541 F.3d 1257, 1266–67 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677–78 (7th Cir. 2008); *c.f. NYPIRG*, 321 F.3d at 333 n.11.

[4] *See also Sierra Club v. Johnson*, 541 F.3d at 1265 ("Congress's use of the word 'shall' . . . plainly mandates an objection *whenever* a petitioner demonstrates noncompliance." (emphasis added)).

[5] *See also Sierra Club v. Johnson*, 541 F.3d at 1265–66; *Citizens Against Ruining the Environment*, 535 F.3d at 678.

[6] *See also, e.g.*, *In the Matter of Noranda Alumina, LLC*, Order on Petition No. VI-2011-04 at 20–21 (December 14, 2012) (denying a title V petition issue where petitioners did not respond to the state's explanation in response to comments or explain why the state erred or the permit was deficient); *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9 at 41 (June 22, 2012) (denying a title V petition issue where petitioners did not acknowledge or reply to the state's response to comments or provide a particularized rationale for why the state erred or the permit was deficient); *In the Matter of Georgia Power Company*, Order on Petitions, at 9–13 (January 8, 2007) (*Georgia Power Plants Order*) (denying a title V petition issue where petitioners did not address a potential defense that the state had pointed out in the response to comments).

petitioner has provided the relevant analyses and citations to support its claims. If a petitioner does not, the EPA is left to work out the basis for petitioner's objection, contrary to Congress's express allocation of the burden of demonstration to the petitioner in CAA § 505(b)(2). *See MacClarence*, 596 F.3d at 1131 ("[T]he Administrator's requirement that [a title V petitioner] support his allegations with legal reasoning, evidence, and references is reasonable and persuasive.").[7] Relatedly, the EPA has pointed out in numerous orders that, in particular cases, general assertions or allegations did not meet the demonstration standard. *See, e.g.*, *In the Matter of Luminant Generation Co., Sandow 5 Generating Plant*, Order on Petition Number VI-2011-05 at 9 (January 15, 2013).[8] Also, the failure to address a key element of a particular issue presents further grounds for the EPA to determine that a petitioner has not demonstrated a flaw in the permit. *See, e.g.*, *In the Matter of EME Homer City Generation LP and First Energy Generation Corp*, Order on Petition Nos. III-2012-06, III-2012-07, and III-2013-02 at 48 (July 30, 2014).[9]

The information that the EPA considers in making a determination whether to grant or deny a petition submitted under 40 C.F.R. § 70.8(d) on a proposed permit generally includes, but is not limited to, the administrative record for the proposed permit and the petition, including attachments to the petition. The administrative record for a particular proposed permit includes the draft and proposed permits; any permit applications that relate to the draft or proposed permits; the statement of basis for the draft and proposed permits; the permitting authority's written responses to comments, including responses to all significant comments raised during the public participation process on the draft permit; relevant supporting materials made available to the public according to 40 C.F.R. § 70.7(h)(2); and all other materials available to the permitting authority that are relevant to the permitting decision and that the permitting authority made available to the public according to § 70.7(h)(2). If a final permit and a statement of basis for the final permit are available during the agency's review of a petition on a proposed permit, those documents may also be considered as part of making a determination whether to grant or deny the petition.

C. New Source Review

The major New Source Review (NSR) program is comprised of two core types of preconstruction permit requirements for major stationary sources. Part C of title I of the CAA establishes the Prevention of Significant Deterioration (PSD) program, which applies to major new sources and major modifications of existing major sources for pollutants for which an area is designated as attainment or unclassifiable for the national ambient air quality standards (NAAQS) and other pollutants regulated under the CAA. CAA §§ 160–169, 42 U.S.C. §§ 7470–7479. Part D of title I of the Act establishes the major nonattainment NSR program, which

[7] *See also In the Matter of Murphy Oil USA, Inc.*, Order on Petition No. VI-2011-02 at 12 (September 21, 2011) (denying a title V petition claim where petitioners did not cite any specific applicable requirement that lacked required monitoring); *In the Matter of Portland Generating Station*, Order on Petition, at 7 (June 20, 2007) (*Portland Generating Station Order).*

[8] *See also Portland Generating Station Order* at 7 ("[C]onclusory statements alone are insufficient to establish the applicability of [an applicable requirement]."); *In the Matter of BP Exploration (Alaska) Inc., Gathering Center #1*, Order on Petition Number VII-2004-02 at 8 (April 20, 2007); *Georgia Power Plants Order* at 9–13; *In the Matter of Chevron Products Co., Richmond, Calif. Facility*, Order on Petition No. IX-2004–10 at 12, 24 (March 15, 2005).

[9] *See also In the Matter of Hu Honua Bioenergy*, Order on Petition No. IX-2011-1 at 19–20 (February 7, 2014); *Georgia Power Plants Order* at 10.

applies to those NAAQS pollutants for which an area is designated as nonattainment. CAA §§ 171–193, 42 U.S.C. §§ 7501–7515.

The PSD program requires a major stationary source to obtain a PSD permit before beginning construction of a new facility or undertaking certain modifications. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1); CAA § 169(2)(C), 42 U.S.C. § 7479(2)(C). Once a source is subject to the PSD permitting program, permitting authorities must address several requirements in issuing a permit, including: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) the application of the Best Available Control Technology (BACT) for each pollutant subject to regulation under the Act. CAA §§ 165(a)(3), (4), 42 U.S.C. §§ 7475(a)(3), (4); 40 C.F.R. § 52.21(j), (k).

The EPA has two largely identical sets of regulations implementing the PSD program. One set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a state implementation plan (SIP). The other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program, which applies in areas without a SIP-approved PSD program. The EPA has approved Utah's PSD program as part of its SIP. *See* 47 Fed. Reg. 6472 (February 12, 1982) (initial approval of Utah PSD program); 40 C.F.R. § 52.2320(c) (listing EPA-approved PSD provisions contained in Utah Admin. Code R307). Utah's PSD provisions are currently contained in Utah Admin. Code R307-101-1, R307-101-2, R307-110-09, R307-401, and R307-405, as approved by the EPA into Utah's SIP.[10]

CAA § 110(a)(2)(c), 42 U.S.C. § 7410 (a)(2)(c), requires that every SIP include a program to regulate the construction and modification of stationary sources, including a permit program as required by parts C and D of title I of the Act, to ensure attainment and maintenance of the NAAQS. While parts C and D address the major NSR program for major sources, section 110(a)(2)(c) addresses the permitting program for new and modified minor sources, and minor modifications to major sources. The EPA commonly refers to the latter program as the "minor NSR" program. States must develop minor NSR programs to attain and maintain the NAAQS. The federal requirements for state minor NSR programs are outlined in 40 C.F.R § 51.160 through 51.164. These federal requirements for minor NSR programs are less prescribed than those for major sources, and, as a result, there is a larger variation of requirements in the minor NSR programs. Utah's EPA-approved minor NSR SIP rules are codified at Utah Admin. Code R307-101-1, R307-101-2, R307-110-3, and R307-401.[11]

In Utah, both major and minor NSR permits issued by UDAQ are termed Approval Orders. An application to obtain an Approval Order is referred to as a Notice of Intent.

[10] Many of Utah's PSD and minor NSR regulations were initially codified in different numbered sections of the Utah Administrative Code, which were subsequently re-numbered.
[11] *See supra* note 10.

III. BACKGROUND

A. The PacifiCorp-Hunter Facility

PacifiCorp Energy is the majority owner and sole operator of the Hunter Power Plant, located in Castle Dale, Emery County, Utah. The PacifiCorp-Hunter plant is comprised of three coal-fired electric utility steam generating units (designated as Units 1, 2 and 3), with a total gross capacity of 1,455 megawatts (MW). Units 1 and 2 are rated at 480 MW and feature dry bottom, tangentially-fired boilers. Unit 3 is rated at 495 MW and features a dry bottom, wall-fired boiler. All three units are currently equipped with low nitrous oxide (NOx) burners/overfire air (for NOx control), a wet flue gas desulfurization system (or scrubber) with no bypass (for sulfur dioxide, or SO_2 control), and a baghouse (for particulate matter, or PM control). The facility is a major stationary source of air pollution.

B. Permitting History

UDAQ initially issued a title V permit to the PacifiCorp-Hunter facility in 1998. Following various permit actions, including several permit amendments and modifications and a renewal permit action in 2005 that was not completed, UDAQ released a draft renewal title V permit on September 15, 2015. After a public comment period that closed on November 13, 2015, UDAQ submitted a proposed title V permit, including a memorandum containing UDAQ's Response to Public Comments (RTC), to the EPA on January 11, 2016. The EPA's 45-day review period concluded on February 25, 2016. The EPA did not object to the proposed permit. UDAQ issued a final title V permit to PacifiCorp-Hunter on March 3, 2016.

C. Timeliness of Petition

Pursuant to the CAA, if the EPA does not object to a proposed permit during its 45-day review period, any person may petition the Administrator within 60 days after the expiration of the 45-day review period to object. 42 U.S.C § 7661d(b)(2). The EPA's 45-day review period expired on February 25, 2016. Thus, any petition seeking the EPA's objection to the 2016 Permit was due on or before April 25, 2016. The Petition was dated and received on April 11, 2016, and, therefore, the EPA finds that the Petitioner timely filed the Petition.

IV. DETERMINATIONS ON CLAIMS RAISED BY THE PETITIONER

Claim A: The Petitioner's Claim that "The Administrator Must Object to the Hunter Permit Because It Fails to Include PSD Requirements For Major Modifications Constructed at Hunter in the Late 1990s."

Petitioner's Claim: The Petitioner claims that the PacifiCorp-Hunter title V permit is deficient because it does not include PSD permitting program requirements—specifically, BACT as well as terms and conditions necessary to adequately protect NAAQS and PSD increments—that the Petitioner asserts are "applicable requirements." Petition at 9, 16. The Petitioner also asserts that the 2016 Permit is deficient because it lacks a compliance schedule to ensure that PacifiCorp-Hunter is brought into compliance with the PSD requirements the Petitioner claims are applicable. *Id.* at 9. The Petitioner claims that these PSD requirements are applicable because they were triggered by modifications to the facility between 1997 and 1999 involving boiler projects and turbine upgrades at all three PacifiCorp-Hunter units, which the Petitioner contends should have been considered "major modifications." *Id.* at 9, 16.

The Petitioner also claims that in applying for an Approval Order authorizing the 1997–1999 boiler and turbine modifications, PacifiCorp-Hunter requested and accepted emission limits restricting its potential to emit to the PSD baseline emission inventory, in order to avoid triggering PSD requirements. *Id.* at 10.[12]

The Petitioner asserts that at the time the projects at issue were undertaken, the Utah SIP regulations for determining whether a project constitutes a major modification were based on the same applicability test as in the EPA's 1980 federal PSD regulations. *Id.* (citing 45 Fed. Reg. at 52676-748 (August 7, 1980)).[13] The Petitioner claims that these rules required a comparison of pre-project actual emissions to post-project potential emissions. *Id.* (citing definitions of "major modification," "net emissions increase," and "actual emissions" contained in Utah Air Conservation Regulation R307-1-1 (1995)).[14]

The Petitioner asserts that, instead of determining applicability by comparing pre-project actual emissions to post-project potential emissions, UDAQ compared the PSD Baseline Inventory (which the Petitioner claims was similar to "allowable" emissions, rather than actual emissions) to post-project potential emissions. *Id.* at 10–11.[15] The Petitioner asserts the "PSD Baseline Inventory" values relied upon were much higher than the facility's actual emissions during the pre-project baseline period. *Id.* at 10–12. The Petitioner presents a summary of the Petitioner's own calculations (based on U.S. Energy Information Administration data and the EPA's AP-42 emission factors) estimating the actual baseline emission values that the Petitioner claims should have been used instead of the "PSD Baseline Inventory." *See id.* at 11–13. Based on these estimated actual emission values, the Petitioner claims that the modifications should have been projected to result in a significant emission increase of SO_2, NOx, PM, and other pollutants at each PacifiCorp-Hunter unit. *Id.* at 12. Moreover, the Petitioner claims that there were no creditable, contemporaneous decreases at the units, and accordingly that the 1997–1999 projects should have been projected to result in a significant net emissions increase of SO_2, NOx, PM, and other pollutants. *Id.* at 14.

---

[12] The Petitioner asserts that these emission limits became ineffectual due to the relaxation of those limits in a 1998 title V permitting action, which incorporated exemptions from these limits during startup, shutdown, and malfunction periods. *Id.* at 15.

[13] The Petitioner claims that although the EPA revised its PSD applicability rules in 1992, the EPA did not approve those changes into the Utah SIP until 2004. Petition at 11 (citing 69 Fed. Reg. 51368, 51368–70 (August 19, 2004); 40 C.F.R. § 52.2320(c)(58)(i)(A)).

[14] The Petitioner also claims that a limited exception within the PSD rules for projects that can be classified as routine maintenance, repair, and replacement, was not applicable. *Id.* at 11.

[15] The Petitioner claims that EPA recently recognized that UDAQ had been applying the same type of faulty PSD applicability analyses in other permitting actions. *Id.* at 14. Specifically, the Petitioner claims that in a permit action for the Deseret Power Electric Cooperative's Bonanza Plant, the EPA highlighted that UDAQ's evaluation of a project "failed to use actual pre-project emissions as the baseline for determining the amount of increase." *Id.* at 14–15 (citations omitted).

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

In responding to the Petitioner's comments on the draft permit, UDAQ did not consider the Petitioner's comments relevant to the title V permit for PacifiCorp-Hunter. UDAQ stated that "[a]ny concerns regarding previous permits should have been raised during public comments at the time those permitting actions took place . . . [A] Title V operating permit does not impose any new requirements but simply brings together all existing requirements from pervious [sic] permitting actions to aid enforcement . . . . The first 100 pages of Sierra Club's letter pertain to the underlying requirements that are now simply incorporated into the Title V operating permit." RTC at 2–3.

This response by UDAQ raises the fundamental issue of whether decisions made during previous preconstruction permitting, like the 1997 Approval Order, should be reconsidered when issuing or renewing a title V operating permit. The Petitioner's Claim A asks the EPA to object to the title V permit for PacifiCorp-Hunter because the title V permit does not include PSD requirements that the Petitioner claims are applicable due to modifications that were approved in the 1997 Approval Order issued by UDAQ under its SIP-approved minor NSR program. The EPA has previously considered similar preconstruction permitting issues when they were raised in citizen petitions for an EPA objection to a state-issued title V permit, but the nature of UDAQ's response and the facts of this case justify a renewed examination of whether such a review is necessary or appropriate in this instance. After a review of the structure and text of the CAA and the EPA's regulations in part 70, in light of the circumstances presented here, the EPA has concluded that the title V permitting process is not the appropriate forum to review the preconstruction permitting decisions addressed in Claim A of the Petition. The EPA is aware that this conclusion differs from the agency's position in prior title V petition orders involving similar circumstances. However, for the legal and policy reasons discussed below, the EPA believes this position better aligns with the structure of the Act and the EPA's original understanding of the relationship between the operating and construction permitting programs under the CAA after the enactment of title V.

Section 504 of the CAA requires that title V permits "include enforceable emissions limitations and standards . . . to assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan." 42 U.S.C. § 7661c(a).[16] However, the term "applicable requirements" is not defined in the Act and the statute does not otherwise

[16] Similar requirements appear in other parts of title V. "Schedule of compliance. The term 'schedule of compliance' means a schedule of remedial measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable implementation plan, emission standard, emission limitation, or emission prohibition" 42 U.S.C. § 7661(3). "Nothing in this subsection shall be construed to alter the applicable requirements of this chapter that a permit be obtained before construction or modification." 42 U.S.C. § 7661a(a). Permitting authorities "have adequate authority to . . . issue permits and assure compliance . . . with each applicable standard, regulation, or requirement under this chapter." 42 U.S.C. § 7661a(b)(5). The regulations to implement the program shall include a "requirement that the applicant submit with the application a compliance plan describing how the source will comply with all applicable requirements under this chapter." 42 U.S.C. § 7661b(b). However, like section 504, these sections do not specify the scope of the term "applicable requirements" or how the permitting authority or the EPA is to determine what the applicable requirements are for an individual source as part of its title V permit.

specify how to determine the "applicable requirements of this chapter" for a particular source. In accordance with Congressional direction, 42 U.S.C. § 7661a(b), the EPA developed regulations to implement the title V program, and those regulations include a definition of the term "applicable requirement."

> *Applicable requirement* means all of the following *as they apply* to the emission units in a part 70 source . . . :
> (1) Any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in part 52 of this chapter [and]
> (2) *Any* term or condition of *any* preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including Parts C or D, of the Act
> . . .

40 C.F.R. § 70.2 (emphasis added).[17] It is clear from this language that the "applicable requirements" include the terms and conditions of preconstruction permits issued under title I of the Act. The language in section (2) of the definition of "applicable requirement" expressly includes both PSD (part C) and nonattainment NSR (part D) permits.

Applicable requirements also include the terms and conditions of minor NSR permits issued pursuant to an approved SIP like the 1997 Approval Order issued for PacifiCorp-Hunter. The context of the rest of the title V regulations and statements in the final preamble support this clear reading. First, the language in section (2) does not indicate that terms and conditions from major NSR permits constitute the only source of "applicable requirements" from preconstruction permits. This reflects a change from the proposed language in section (2) which only included major NSR permitting: "any preconstruction permits issued pursuant to title I, part C or D of the Act." 56 Fed. Reg. 21738, 21768 (May 10, 1991). When the EPA explained the change in the definition of "applicable requirement" in the final part 70 rules, the EPA stated that the changes were "to clarify that applicable requirements include terms and conditions of preconstruction permits *issued pursuant to SIP's* and other regulations approved by the EPA in formal rulemaking after notice and an opportunity for public comment." 57 Fed. Reg. 32250, 32276 (July 21, 1992) (emphasis added).[18] This change makes clear that the EPA viewed the terms and conditions of *all* preconstruction permits as "applicable requirements," including minor NSR permits issued pursuant to an approved SIP.[19]

---

[17] Utah's title V regulations employ a parallel structure to define applicable requirement to include:
"(a) Any standard or other requirement provided for in the State Implementation Plan;
(b) Any term or condition of any approval order issued under R307-401" R307-415-3.

[18] The meaning of the phrase "preconstruction permits issued pursuant to . . . other regulations" was not discussed in the preamble, but is best understood to ensure that preconstruction permits issued pursuant to federal regulations, like federal PSD permits issued pursuant to 40 C.F.R. § 52.21 or other permits issued under Federal Implementation Plans (FIPs), are included in a title V permit as applicable requirements.

[19] This is buttressed by other provisions in part 70. For instance, while allowing interim approval of state programs to issue title V permits that do not include all minor NSR permit requirements, 40 C.F.R. § 70.4(d) makes clear that the terms and conditions of minor NSR permits must eventually be included in the source's title V permit. *Accord*

Therefore, if a minor preconstruction permit has been issued under an approved title I program, the clear meaning of the second section of the definition of "applicable requirement" at 40 C.F.R. § 70.2 requires that the terms and conditions of that minor preconstruction permit are included in a source's title V permit.

However, the definition of "applicable requirement" does not on its face include the requirement to obtain a preconstruction permit in the first instance. The Petition addressed in this Order argues that PacifiCorp-Hunter failed to obtain such a required permit. As discussed in detail below, *see infra* p. 11–13, the EPA has previously construed section (1) of the definition of "applicable requirement" to cover the requirement to obtain a preconstruction permit. Specifically, the EPA has read the phrase "[a]ny standard or other requirement provided for in the applicable implementation plan" to include the *requirement to obtain* a preconstruction permit. *See e.g., In the Matter of Shintech, Inc.*, Order on Petition, Permit Nos. 2466-VO, 2467-VO, 2468-VO at 3 n.2 (September 10, 1997) (emphasis added). But when a source *has obtained* a preconstruction permit, for purposes of writing a title V permit, this presents an ambiguity in the definition of "applicable requirement" because section (2) includes the terms and conditions of that permit. The EPA has previously interpreted its regulations to apply both sections (1) and section (2) to title I preconstruction permitting requirements after a preconstruction permit has been obtained. But this reading can lead to a requirement that a title V permitting authority or the EPA reconsider, in issuing a title V permit or responding to a petition, whether a validly issued preconstruction permit is the appropriate type of permit. While such an expansive reading of section (1) may have been applied by the EPA in the past in title V petition responses, this leads to an incongruous result that is inefficient and can upset settled expectations—on the part of a state, an owner/operator, and the public at large—in circumstances where a source has obtained a legally enforceable preconstruction permit in accordance with the requirements of title I.

In circumstances such as those present here where a preconstruction permit has been duly obtained, the regulations should be read to mean, consistent with the EPA's contemporaneous expressions of the purpose of title V permitting, that when a permitting authority has made a source-specific permitting decision with respect to a particular construction project under title I, those decisions "define certain applicable SIP requirements for the title V source" for purposes of title V permitting. 57 Fed. Reg. 32250, 32259 (July 21, 1992). The EPA is now interpreting the regulations to mean that the issuance of a minor NSR permit defines the applicability of preconstruction requirements under section (1) of the definition of "applicable requirement" for the approved construction activities for the purposes of permitting under title V of the Act.[20] These source-specific permitting actions take the general preconstruction permitting requirements of the SIP—the requirement to obtain a particular type of permit and the substantive requirements that must be included in each type of permit—and evaluate at the time

---

Public Citizen, Inc. v. US EPA, 343 F.3d 449, 459-460 (5th Cir. 2003) (noting that the EPA granted interim, instead of final, approval to Texas's title V program because—along with other deficiencies—the program failed to recognize the terms and conditions of minor NSR permits as applicable requirements). It is also clear that the EPA was aware of how to distinguish between preconstruction permits issued under title I and only major NSR permits. For instance, in 40 C.F.R. § 70.7(a)(3), which requires reasonable procedures for giving priority to major NSR permits under parts C and D, the requirement is clearly not extended to minor NSR permits.

[20] A minor preconstruction permit only defines the applicable requirement for purposes of title V permitting. The interpretation today does not address anyone's ability to review under other titles of the Act a determination that major NSR was not applicable. *See infra* p. 20–21.

of the permitting decision whether and how to apply them to a proposed construction or modification. The definition of "applicable requirement" says that the determination of "applicable requirements" is "as they apply" to the source and includes "any term or condition of any preconstruction permits issued." 40 C.F.R. § 70.2. In issuing a preconstruction permit to a source, the permitting authority provides the terms and conditions of the preconstruction permitting requirements of the SIP "as they apply" to the source at that time for purposes of inclusion into the title V permit. *Id.* In the circumstance present here, the source-specific preconstruction permit issued by UDAQ determined for purposes of title V permitting the preconstruction requirements of the Utah SIP under section (1) of the definition of "applicable requirement" for the particular modification that was permitted. When UDAQ applied those requirements of the SIP to issue the preconstruction permit, it derived the source-specific "applicable requirements" for purposes of section (2) of that definition.[21] The EPA finds no error in UDAQ's decision in this case to incorporate the terms and conditions of the previously issued preconstruction permits into the title V operating permit without further review of whether those conditions were properly derived or whether a different type of permit was required for the same construction activity.

Previous Interpretations by the EPA

This reading of the regulations comports with the EPA's statements regarding the relationship between the CAA's preconstruction and operating permit requirements at the time that the EPA initially issued the title V regulations in part 70. The EPA did not express the intention to use the title V permitting process to review the "applicable requirements" established in preconstruction permitting programs under title I of the CAA. To the contrary, the EPA stated that "[a]ny requirements established during the preconstruction review process also apply to the source for purposes of implementing title V. If the source meets the limits in its NSR permit, the title V operating permit would incorporate these limits *without further review*." Proposed Operating Permit Program, 56 Fed. Reg. 21712, 21738–39 (May 10, 1991) (emphasis added). The EPA stated clearly that "[t]he intent of title V is not to second-guess the results of *any* State NSR program." *Id.* at 21739 (emphasis added) (1991 Preamble). The EPA stated that "[d]ecisions made under the NSR and/or PSD programs (e.g., [BACT] *define applicable SIP requirements* for the title V source and, if they are not otherwise changed, can be incorporated without further review into the operating permit for the source." *Id.* at 21721 (emphasis added).

However, as indicated in the Petition, *see infra* Claim E, the EPA later shifted away from this understanding of part 70 (title V) permitting in circumstances where a source had already obtained a title I preconstruction permit. In title V orders and guidance documents in the late 1990s, the EPA began to interpret section (1) of the definition of "applicable requirement" to allow the EPA and states to examine the propriety of prior construction permitting decisions in the title V permitting process.

For instance, in *In the Matter of Shintech, Inc.*, Order on Petition, Permit Nos. 2466-VO, 2467-VO, 2468-VO at 3 n.2 (September 10, 1997), the EPA said:

[21] This interpretation applies to the facts of this Claim, where a permitting authority issued a source-specific title I preconstruction permit subject to public notice and comment and for which judicial review was available. The EPA is not considering at this time whether other circumstances may warrant a different approach.

> Where a state or local government has a SIP-approved PSD program, the merits of PSD issues can be ripe for consideration in a timely petition to object under Title V. Under 40 CFR § 70.1(b), "all sources subject to Title V must have a permit to operate that assures compliance by the source with all applicable requirements." Applicable requirements are defined in section 70.2 to include "(1) any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under Title I of the [Clean Air] Act…." The LDEQ defines "federal applicable requirement, in relevant part, to include "any standard or other requirement provided for in the Louisiana State Implementation Plan approved or promulgated by EPA through rulemaking under title I of the Clean Air Act that implements the relevant requirements of the Clean Air Act, including any revisions to that plan promulgated in 40 CFR part 52, subpart T." LAC 33:III.502. Thus, the applicable requirements of the Shintech Permits include the requirement to obtain a PSD permit *that in turn complies with the applicable PSD requirements under the Act*, EPA regulations, and the Louisiana SIP. (emphasis added)

In a 1999 letter responding to requests from permitting authorities, the Director of the Office of Air Quality Planning and Standards articulated the EPA's then-current understanding of the interaction of title I and title V. Letter from John S. Seitz, U.S. EPA, to Robert Hodanbosi, STAPPA/ALAPCO (May 20, 1999).[22] The letter stated that "applicable requirements include the requirement to obtain preconstruction permits that comply with applicable preconstruction review requirements under the Act, EPA regulations, and SIP's." *Id.* Enclosure A at 2. The letter expressed the view that section 505(b) of the Act provides a form of corrective action in addition to all the other enforcement authorities the EPA has under the Act. *Id.* While it stated that generally the agency will not object to a title V permit for determinations "made long ago[,] . . . EPA may object to [a more recent] title V permit due to an improper [preconstruction] determination." *Id.* Enclosure at 2-3. Additionally, the letter said that the EPA could object to a title V permit where "EPA believes that an emission unit has not gone through the proper preconstruction permitting process." *Id.* Enclosure at 3.[23] However, the letter did not provide any explanation for why decisions "made long ago" were entitled to more deference than recent decisions for purposes of title V permitting.

More recently, the EPA has implicitly or explicitly assumed that preconstruction permitting decisions were ripe for review when responding to title V petitions. For instance, while not substituting its own judgment for that of a state permitting authority, the EPA has reviewed

---

[22] *Available* at *https://www.epa.gov/sites/production/files/2015-08/documents/hodan7.pdf.*

[23] The EPA has also used this reading of the agency's oversight authority under title V as part of the justification for approving state PSD programs. *See* Approval and Promulgation of Implementation Plans; Oregon, 68 Fed. Reg. 2891, 2899 (January 22, 2003); *see also* Approval and Promulgation of Implementation Plans; Idaho; Designation of Areas for Air Quality Planning Purposes; Idaho, 68 Fed. Reg. 2217, 2221 (January 16, 2003). In these approvals the EPA pointed to its authority under title I, sections 113 and 167, and stated that title V "has added new tools" for addressing concerns with implementation of PSD requirements by allowing for objection to title V permits under section 505(b) of the Act. However, the authority to revisit an issued preconstruction permit does not appear to have been dispositive to the approval of these PSD programs as EPA could still conduct oversight using its enforcement authorities. *See infra* p. 20–21.

whether a petitioner demonstrated that the permitting authority's exercise of discretion under its SIP-approved regulations was unreasonable or arbitrary. *See e.g., In the Matter of American Electric Power – John W. Turk Plant*, Order on Petition No. VI-2008-01 (December 15, 2009); *In the Matter of Cash Creek Generation*, Order on Petition Nos. IV-2008-1 & IV-2008-2 (December 15, 2009) ("Cash Creek I"); *In the Matter of Cash Creek Generation*, Order on Petition No. IV-2010-4 (June 22, 2012) ("Cash Creek II"). The EPA has also considered applicability of major NSR in responding to petitions. *See e.g., In the Matter of CEMEX, Inc. – Lyons Cement Plant*, Order on Petition VIII-2008-01 (April 20, 2009); *In the Matter of Wisconsin Power and Light – Columbia Generating Stations*, Order on Petition No. V-2008-1 (October 8, 2009). In these title V orders, the EPA indicated that the agency could review whether previous preconstruction permitting decisions complied with the requirements of the SIP, which would appear to be inconsistent with the preamble of the regulations in part 70 described above.[24]

However, at the same time, the EPA has declined in the title V petition context to review the merits of PSD permits issued by the agency or by a permitting authority that has received delegation to implement the EPA's federal PSD rules. *See In the Matter of Kawaihe Cogeneration Project*, Order on Petition, Permit No. 0001-01-C (March 10, 1997). Because these permitting decisions may be appealed to the EPA's Environmental Appeals Board, the EPA has concluded that it need not entertain claims that such permits are deficient when raised in a petition to object to a title V permit.

The EPA's Approach Moving Forward

Notwithstanding the interpretation advanced with respect to title I permitting under SIP-approved programs in these previous orders and policy statements, there are many reasons to view the EPA's original interpretation of the regulations governing title V permitting to be more appropriate given the policy and legal reasons explained below.

First, the interpretation expressed in this Order—that preconstruction permit terms and conditions should be incorporated without further review—aligns with that expressed contemporaneous with the promulgation of the title V regulations in 40 C.F.R. part 70. This provides the best indication of the intention of the agency when it issued those regulations. A contemporaneous interpretation is often given great weight in understanding the meaning of a

[24] However, during this time the EPA has suggested that the demonstration burden may require a final determination to overturn an applicability decision made by the permitting authority. In denying a petition for objection in *In the Matter of Midwest Generation-Joliet Generating Station and Will County Generating Stations*, Order on Petition No. V-2005-2 at 9 (June 14, 2007), the EPA stated that the permitting authority "has not reached a final determination in this permitting context that PSD is an applicable requirement for these sources, that the USEPA has not determined otherwise, and that a court has not issued a determination in the litigation context. Accordingly, there is no requirement under the facts of this case for the permits to include either PSD limits or a compliance schedule for the source to come into compliance with such limits at this time." The EPA concluded that "even if IEPA were to recognize that the potential for noncompliance [with title I preconstruction permitting requirements] exists, it is not required to pursue inquiries further in the title V context." *Id.* at 10. This is consistent with the approach advanced in this Order that instead of reviewing preconstruction permitting decisions in title V, oversight of title I preconstruction permitting decisions should be conducted under title I authorities, such as enforcement actions under section 113 or section 167, or state court appeals of preconstruction permits, or through citizen enforcement actions under section 304.

statute. *See e.g.*, *Good Samaritan Hosp. v. Shalala*, 508 U.S. 402, 414 (1993) ("Of particular relevance is the agency's contemporaneous construction which 'we have allowed . . . to carry the day against doubts that might exist from a reading of the bare words of a statute'" (citing *FHA v. The Darlington, Inc.*, 358 U.S. 84, 90 (1958))). Much as an agency's contemporaneous interpretation of a statute through a regulation is given great weight, an agency's contemporaneous interpretation of its own regulations in the preamble for those regulations should carry similar weight.

More importantly, this reading—that title V permitting is not intended to second-guess the results of state preconstruction permit programs—is better aligned with the structure and purpose of title V itself. As the EPA and courts have noted on many occasions, title V was not intended to add new substantive requirements. *See e.g.*, *United States Sugar Corp. v. EPA*, 830 F.3d 579, 597 (D.C. Cir. 2016) ("Title V does no more than consolidate 'existing air pollution requirements into a single document, the Title V permit, to facilitate compliance monitoring' without imposing new substantive requirements." (quoting *Sierra Club v. Leavitt*, 368 F.3d 1300, 1302 (11th Cir. 2004)); *United States v. Cemex, Inc.*, 864 F.Supp.2d 1040, 1045 (D. Colo. 2012) ("'Title V permits do not generally impose any new emission limits, but are intended to incorporate into a single document all of the Clean Air Act requirements applicable to a particular facility' and to provide for monitoring and other compliance measures" (quoting *United States v. EME Homer City Generation L.P.*, 823 F.Supp.2d 274, 283 (W.D. Pa. 2011))).

Title V contains no language that says that this consolidation process must involve a review of the substantive adequacy of any "applicable requirements" or a reconsideration whether the "applicable requirements" were properly derived. This would entail much more than taking steps to "consolidate 'existing air pollution requirements.'" *United States Sugar Corp. v. EPA*, 830 F.3d at 597. As the courts have acknowledged, the purpose of the title V program is to identify which of the myriad of requirements under the CAA are applicable to an individual source. These include many requirements that are broadly applicable to entire categories of sources or sources with particular characteristics. In this case, the preconstruction requirements under the Act are different than many of these other requirements in that they were derived on a case-by-case basis in a source-specific process that produced permit terms and conditions that are expressly applicable to an individual source. But the Act does not say that "applicable requirements" with these characteristics must be checked to determine if they were properly derived before they can be consolidated into an operating permit. Neither does the Act demand that these "applicable requirements" be re-checked each time the operating permit is renewed.

Before title V of the CAA was enacted, Congress enacted the title I preconstruction permitting requirements in the 1977 Amendments to the CAA. At that time, Congress understood that the adequacy of state preconstruction permitting decisions would be subject to review in state administrative and judicial forums.[25] Congress has also given the EPA specific oversight authority under title I to, among other authorities, approve or disapprove state permitting

[25] "In order to challenge the legality of a permit which a State has actually issued ... a citizen must seek administrative remedies under the State permit consideration process, or judicial review of the permit in State court." Staff of the Subcommittee on Environmental Pollution of the Senate Committee on Environment and Public Works, 95th Congress, 1st Session, A Section-by-section Analysis of S. 252 and S. 253, Clean Air Act Amendments 36 (1977), reprinted in 5 Legislative History of the Clean Air Act Amendments of 1977 3892 (1977).

programs, 42 U.S.C. § 7410(a)(2)(C), call for revisions to those programs, *id.* § 7410(k)(5), issue injunctive orders to halt construction, *id.* § 7477, and pursue various types of enforcement actions pursuant to sections 113 and 167 of the Act, *id.* § 7413, § 7477.

There is no clear indication in the terms of the 1990 Amendments to the CAA or its legislative history that the addition of the title V provisions to the Act was intended to add another opportunity to review the merits of a construction permitting decision in addition to the title I authorities that existed already or that were added as part of the 1990 Amendments. There is no clear indication that Congress intended to alter the balance of oversight that the EPA had over state preconstruction permitting through title V review. Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001). A reading of part 70 that would transform title V into an opportunity to reevaluate previous preconstruction approvals, instead of simply incorporating existing air pollution requirements into one document, would "alter the fundamental details" of the oversight authorities the EPA has under title I of the Act. For instance, instead of disapproving the preconstruction requirements in a state SIP or issuing a stop construction order to an individual source, which Congress explicitly authorized, the EPA could issue administrative orders on a case-by-case basis under title V.[26] The text of the Act does not indicate that Congress intended to create this type of additional administrative oversight mechanism for preconstruction permitting actions in an operating permit program designed to consolidate and enforce existing requirements. While there is language in title V requiring that a permit "assure compliance with applicable requirements of this chapter," *e.g.*, 42 U.S.C. § 7661c(a), and similarly broad language, this type of general language does not clearly or specifically say that a title V permitting authority must reevaluate preconstruction permitting decisions that have already been made under title I each time that it issues or renews a title V permit. Consistent with the EPA's contemporaneous interpretation of its part 70 regulations, this general language in the statute should be read to mean that the title V permit must include conditions to ensure compliance with the terms and conditions of the source-specific preconstruction permits that have been issued for the source. Absent language providing a clearer or direct indication that the provisions in title V of the Act require the reevaluation of preconstruction permitting decisions for a source, the EPA is determining that it should not read general and broad terms to find such a preconstruction permitting oversight tool "hidden" in the title V permitting program.

The EPA's preconstruction permitting oversight authority under title I of the Act supports reading the title V provision to supply a more limited oversight role for the EPA with regard to state implementation of preconstruction permitting programs.[27] The EPA believes that in-depth oversight of case-specific state title I permitting decisions should be handled under title I, such as through the state appeal process or an order or action under sections 113 or section 167. Citizen oversight may still be accomplished through the state appeal process or through a citizen suit

[26] As described in more detail below, an interpretation of title V that excludes revisiting preconstruction decisions does not fundamentally alter or limit the EPA's authority under title I of the Act and, absent specific circumstance does not provide an effective title V permit shield. *See infra* p. 20–21.

[27] *See* 42 U.S.C. § 7401(a)(3) ("The Congress finds . . . air pollution control at its source is the primary responsibility of States and local governments.")

under title III. As described in this Order, for purposes of title V, the permitting authority should incorporate the terms and conditions of preconstruction permits into the source's title V permit, unless and until those preconstruction permits are revised, reopened, suspended, revoked, reissued, terminated, augmented, or invalidated through one of these mechanisms.[28] Similarly, broader programmatic issues should be handled under the EPA's existing title I authorities instead of through case-by-case objections under title V.

Other provisions of title V support the interpretation in this Order rather than an obligation to reevaluate previous permitting decisions. For instance, title V requires state programs to have "[a]dequate, streamlined, and reasonable procedures . . . for expeditious review of permit actions . . ." 42 U.S.C. § 7661a(b)(6). Requiring a permitting authority, or the EPA, to go back and review final permitting decisions that have already been subject to the safeguards of public notice and judicial review could frustrate the goal of "expeditious review of permit action." The facts underlying this Order bear this out. If, instead of simply incorporating the terms and conditions of the 1997 Approval Order, UDAQ were required to reevaluate that decision now and each time it renews the title V permit in the future, then it could require substantial resources and unsettle expectations and reliance interests on the part of the state, owner/operators, and the broader public. UDAQ would have to find any data or analyses that were used 20 years ago or more, to justify its title V permitting decision.[29]

Similarly, Congress also provided abbreviated timeframes for the EPA to review a proposed title V permit: 45 days for the EPA's independent review, and 60 days if confronted with a petition to object. 42 U.S.C. § 7661d(b). These timeframes are inconsistent with an in-depth and searching review of every source-specific preconstruction permitting decision that has previously been made by the permitting authority.[30] Instead, these provisions suggest that the EPA's role in oversight over the issuance of title V permits should be limited. The Administrator will object to a title V permit if it does not include the "applicable requirements" or does not otherwise comply with part 70. 40 C.F.R. § 70.8(c). The EPA's oversight ensures that the permitting authority has properly included the "applicable requirements" as they apply to the source[31] and follows the requirements of title V by including adequate monitoring, recordkeeping, and reporting to assure compliance with those requirements. *See* 42 U.S.C. § 7661c(a), 7661c(c); 40 C.F.R. § 70.6(a)(3),

[28] In this way, this interpretation is consistent with the EPA's statements in *In the Matter of Midwest Generation-Joliet Generating Station and Will County Generating Station*, Order on Petition No. V-2005-2 (June 14, 2007). *See supra* note 24 and accompanying text.

[29] In fact, it may simply be impossible in a title V permitting action to recreate a complete defensible administrative record to support the review of a preconstruction permitting decision made long ago. For instance, it appears records from the NSR section of DAQ are only maintained by the Utah Division of Archives and Record Services for 11 years. *See* Utah Division of Archives and Record Service, Records Management, Series 22001, page 81, New Source Review Section green copies, *available at https://axaemarchives.utah.gov/cgi-bin/pdfreport.cgi?agency=00062&INCLUDE_CLOSED=N&A=B.*

[30] For instance, here the Petition itself is 36 pages and includes 8 separate attachments. However, this includes the Petitioner's comments to UDAQ on the draft title V permit and the associated attachments. The Petitioner's comments are 127 pages and includes 93 separate attachments.

[31] For instance, the EPA would review whether the title V permit includes all the terms and conditions of the preconstruction permit and whether they appear as they appear in the preconstruction permit. If terms or conditions are left out, then title V permit does not include all the applicable requirements, i.e., the terms and conditions of the preconstruction permit.

70.6(c)(1). In the case of a preconstruction permit, the EPA's oversight role under title V is to ensure that the terms and conditions of the preconstruction permit are properly included as "applicable requirements," and that the permit contains monitoring, recordkeeping, and reporting sufficient to assure compliance with those permit terms and conditions.

It is inefficient for permitting agencies, and the EPA,[32] to review as part of the title V permitting process the preconstruction permitting decisions that have already been subject to public notice and comment and an opportunity for judicial review. In the case of the 1997 Approval Order issued to PacifiCorp-Hunter, the public notice specifically stated that the Approval Order included emission limits intended to avoid the need for the source to obtain a PSD permit. In the notice for the 1997 Approval Order, published on October 9, 1997, UDAQ stated that:

> Pacificorp [sic] is requesting that additional enforceable emission limits be established which will limit the potential to emit (PTE) from this source. These limits are being imposed to demonstrate that the consolidation will not exceed the Prevention of Significant Deterioration (PSD) baseline emission inventory. A number of projects, which may increase the capacity or capacity utilization of the three units, have been planned or completed. The net effect of these projects could be an increase in emissions, hence the newly requested limits to insure an emissions decrease.

Sierra Club's Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number: 1500101002-Draft), Exhibit 91, at 3. The Utah Administrative Procedures Act (UAPA) allows an aggrieved party to obtain judicial review of a final agency action like UDAQ's issuance of the 1997 Approval Order. *See* Utah Code § 63G-4-401(1) (renumbered from Utah Code § 63-46b-14(1) by 2008 Utah Laws ch. 382, § 1391). Utah provided the public with an opportunity to submit comments on the manner in which UDAQ was proposing to set the baseline emission rate in the proposed 1997 Approval Order. Had those comments not convinced UDAQ to change its proposed permitting decision or if UDAQ's response to those comments had been inadequate, the public had the right to challenge UDAQ's decision in state court under the UAPA. Yet, no one availed themselves of these available remedies to correct what the Petitioner claims are invalid readings of the Utah SIP and the CAA. The Petitioner is now, in essence, asking for a "second bite at the apple" through EPA oversight in title V. The availability of notice, opportunity to comment, and ability to seek judicial review of the underlying preconstruction permit—here issued *twenty years ago*—weigh heavily against an interpretation of title V as being an appropriate avenue to reevaluate these previous permitting authority decisions made by UDAQ.

Additionally, the availability of these avenues to address concerns with preconstruction permitting decisions at the time they were made illustrates how the title V permitting process and the EPA's oversight of state title V permits are ill-suited forums for considering these issues. As noted above, the EPA only has 45 days and 60 days to review a title V permit and any subsequent petition to object, respectively. Given the complex technical review required to consider some of the substantive requirements of a preconstruction permit, this timeframe is

[32] Title I of the CAA specifically contemplates that the "interested persons" who may comment on state-issued PSD permits include "representatives of the Administrator." 42 U.S.C. § 7475(a)(2).

often inadequate to fully consider the issues presented. A state adjudicatory process or an enforcement action would allow more time for development and consideration of the potential issues raised in a state's application of preconstruction permitting requirements—another indication that these state processes and mechanisms are the appropriate forum for resolving preconstruction permitting issues.

The interpretation of the title V rules and statutory provisions reflected in this Order also respects the finality of the permitting authority's preconstruction permitting decision. Because that decision was reached through a process that included public input and the opportunity for judicial review, it would not be appropriate for the EPA to raise questions at a later date about the state's final decisions through a limited administrative review process via title V. Other avenues for consideration of these issues allow for more input and review than the title V petition process. The interpretation of the title V rules and statutory provisions reflected in this Order more closely aligns, for purposes of title V permitting, the respect the EPA accords permits that are issued pursuant to federal regulations and reviewable by the Environmental Appeals Board with those like the 1997 Approval Order that are issued pursuant to federally-approved state regulations and are reviewable in state administrative tribunals and courts. *See In the Matter of Kawaihe Cogeneration Project*, Order on Petition, Permit No. 0001-01-C (March 10, 1997). Given that the EPA's oversight of title V permitting is ill-suited to serve as a forum for considering these kinds of potentially complex problems, it makes sense that for purposes of title V permitting, permitting authorities and the EPA should only consider whether the terms and conditions of final preconstruction permitting decisions made under title I have been properly included in a title V operating permit and whether there is sufficient monitoring, recordkeeping, and reporting to assure compliance with those terms and conditions.

The interpretation of the title V rules and statutory provisions reflected in this Order also aligns the EPA's treatment of preconstruction permits with how the EPA has consistently treated other "applicable requirements" under title V. For many other "applicable requirements," the EPA does not reconsider the content of those requirements in title V or in its oversight role of title V permitting. For instance, the EPA would not allow a permitting authority to revise the substantive requirements of New Source Performance Standards established under section 111, or National Emission Standards for Hazardous Air Pollutants established under section 112.[33] These substantive requirements have already been established pursuant to a process that included public notice and comment and the opportunity for judicial review.[34] It would, therefore, be inappropriate to reevaluate these standards in title V permitting. Likewise, source-specific preconstruction permitting that includes consideration of applicability of SIP preconstruction requirements that has been put out for notice and comment and the opportunity judicial review has gone through a similar process at the state level. For purposes of title V permitting, it makes sense to treat decisions that go through similar processes similarly.

[33] As noted above, the permitting authority may use the title V permit to consider enhancing the monitoring, recordkeeping, or reporting under these standards. *See e.g., In the Matter of Wheelabrator Baltimore*, Order on Petition, Permit No. 24-510-01886 at 11–13 (April 14, 2010).
[34] However, the applicability of these standards to the particular source would not necessarily have been through such a process. To the extent that the applicability of these standards has not been subject to notice and comment and the opportunity for judicial review, it may be appropriate for EPA to review the applicability to a particular source in title V permitting.

The EPA has also declined to second-guess the content of "applicable requirements" even when a title V permit incorporates SIP provisions that the EPA has determined are inconsistent with the CAA. The EPA has said that the proper forum to address whether a SIP provision is inconsistent with the CAA is through a "SIP Call" under section 110(k). *In the Matter of Piedmont Green Power*, Order on Petition Number IV-2015-2 at 28–29 (December 13, 2016) (*Piedmont Green Power Order*); *see In the Matter of Midwest Generation, LLC, Joliet Generating Station*, Order On Petition No. V-2004-5 at 17, 20–21, 23–24 (June 24, 2005) ("[A] permitting authority cannot use a title V permit to modify a requirement from a federally approved SIP.").[35] Until the EPA approves a corrective SIP revision or issues a FIP, no action within the title V permits is required. *Piedmont Green Power Order* at 29. Even though the EPA has concluded that the SIP provision is inconsistent with the Act, the title V permit should continue to incorporate the SIP provision because it is an "applicable requirement." Similarly, just because the EPA does not object to a title V permit that includes the terms and conditions of a title I permit, it does not suggest that the EPA agrees that those terms and conditions comply with the applicable SIP or the CAA. However, until the terms and conditions of the title I permit are revised, reopened, suspended, revoked, reissued, terminated, augmented, or invalidated through some other mechanism, such as a state court appeal or enforcement action, the "applicable requirement" remains the terms and conditions of the issued preconstruction permit and they should be included in the source's title V permit. Consistent with 40 C.F.R. part 70, this Order treats the reviewability of final preconstruction permitting decisions made by the permitting authority in a manner similar to those decisions made in promulgating the SIP for purposes of title V permitting.

For these reasons, the interpretation in this Order of title V and part 70 (and embodied in the 1991 Preamble) more closely aligns with the intent and purpose of title V than the departure from that interpretation expressed in certain previous orders and other agency statements, as discussed above. Consistent with this reading, permitting agencies and the EPA need not reevaluate—in the context of title V permitting, oversight, or petition responses—previously issued final preconstruction permits, especially those that have already been subject to public notice and comment and an opportunity for judicial review. Concerns with these final preconstruction permits should instead be handled under the authorities found in title I of the Act. Where a final preconstruction permit has been issued, whether it is a major or minor NSR permit, the terms and conditions of that permit should be incorporated as "applicable requirements" and the permitting authority and the EPA should limit its review to whether the title V permit has accurately incorporated those terms and conditions and whether the title V permit includes adequate monitoring, recordkeeping, and reporting requirements to assure compliance with the terms and conditions of the preconstruction permit. *See* 42 U.S.C. § 7661c(a); 40 C.F.R. § 70.6(a)(3), 70.6(c)(1).

The CAA requires the EPA to object to a permit if the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2). "The Administrator shall include in regulations under this subchapter provisions to implement" the title V petition process. *Id.* The EPA's title V regulations state that the

[35] See also; *In the Matter of Monroe Power Company*, Order on Petition IV-2001-8 at 14 (October 9, 2002); *In the Matter of Pacificorp's Jim Bridger and Naughton Electric Utility Steam Generating Plants*, Order on Petition No. VIII-00-1 at 23-24 (November 16, 2000).

"Administrator will object to the issuance of any proposed permit determined by the Administrator not to be in compliance with *applicable requirements* or requirements under this part." 40 C.F.R. § 70.8(c)(1) (emphasis added). If the EPA does not object during its 45-day review period, any person may petition the EPA to issue "such objection." 40 C.F.R. § 70.8(d).

The Petitioner has not alleged that UDAQ did not incorporate the terms and conditions of a preconstruction permit "issued pursuant to regulations approved or promulgated through rulemaking under title I." 40 C.F.R. § 70.2 (definition of "applicable requirement"). Further, the Petitioner has not alleged that the monitoring, recordkeeping, or reporting found in the title V permit are inadequate to assure compliance. Therefore, the Petitioner has not demonstrated in Claim A that the title V permit is "not . . . in compliance with applicable requirements" or the requirements of part 70. 40 C.F.R. § 70.8(c)(1); *see* 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d). The EPA therefore denies the Petition with regard to Claim A.

Interaction with Enforcement

The interpretation of the provisions of title V and part 70 reflected in this Order does not limit the EPA's preconstruction permit oversight or enforcement authority under title I of the Act. For example, the EPA retains the ability to bring an enforcement action under section 113 alleging a violation of title I of the Act for a source's failure to obtain a major NSR (PSD or nonattainment NSR) permit where the EPA has evidence that the construction or modification of a source triggered NSR permitting requirement. The EPA's view that reevaluation of NSR permits is not appropriate in the context of a title V permit does not diminish the opportunities to review construction permitting decisions under title I of the CAA. Where an EPA investigation indicates that a source failed to obtain a required permit (even if a minor source permit was obtained), the EPA may seek to remedy its disagreement with state permitting decisions through enforcement actions. *See e.g., U.S. v. S. Ind. Gas & Elec. Co.*, No. IP99-1692-CM/F, 2002 WL 1760699, at *3-5 (S.D. Ind. July 26, 2002); *United States v. Ford Motor Co.*, 736 F. Supp. 1539, 1550 (W.D. Mo. 1990). This is not inconsistent with the EPA's view of the role of title V of the Act as addressed in this Order.

That the EPA views the incorporation of the terms and conditions of these preconstruction permits into the title V operating permit as proper for purposes of title V does not indicate that the EPA agrees that the state reached the proper decision when setting terms and conditions in the preconstruction permits. For instance, even when the EPA has made a determination that a provision of the SIP is not in compliance with the Act, the EPA will not object to a permit that includes that provision until there is final action to remove it from the SIP. *Piedmont Green Power Order* at 28-29; *see also supra* discussion on p. 19. The EPA's lack of objection to the inclusion of that requirement in the title V permit does not indicate that the EPA agrees that it is legal or complies with the Act; it merely indicates that a title V permit is not the appropriate venue to correct any such flaws in the preconstruction permit. Similarly, even though the EPA might disagree with the preconstruction permitting decisions made by the permitting authority, for purposes of the title V operating permit, the terms of the preconstruction permit should be incorporated into the title V operating permit until such time that there is a final action to revise, reopen, suspend, revoke, reissue, terminate, augment, or invalidate the preconstruction permit, such as a court order in a state court appeal or through an enforcement action.

The incorporation of the terms and conditions of the minor NSR permit into the title V permit does not, by itself, diminish the ability to review the preconstruction permitting decision in an enforcement action by the EPA or citizens. The EPA does not view this interpretation of the part 70 regulations as changing the agency's interpretation or enlarging the scope of a permit shield under 42 U.S.C. § 7661c(f) and implementing regulations in 40 C.F.R. § 70.6(f). A permit shield, if part of an approved title V program and included in the title V permit, would only provide a sufficient defense from enforcement actions that allege a major NSR permit is required when the facility only received a minor NSR permit under certain circumstances.

There are two types of "permit shields"' under title V. The first, default "permit shield"' states that compliance with the title V permit "shall be deemed compliance with" title V. 42 U.S.C. § 7661c(f). However, where a facility is entitled only to this default permit shield, requirements of the CAA outside of title V are still independently enforceable against the facility. A permitting authority may go farther to provide a facility with a second, more expansive type of permit shield. Under the first prong of an expanded permit shield, the permitting authority can provide that compliance with the title V permit "shall be deemed compliance with other [non-title V] applicable provisions" if "the permit includes the applicable requirements of such provision." *Id.* Otherwise, the permitting authority can only provide a shield from non-applicable requirements if it "in acting on the permit application makes a determination relating to the permittee that such other provisions (which shall be referred to in such determination) are not applicable and the permit includes the determination or a concise summary thereof." *Id.* While the EPA interprets the issuance of a final minor NSR permit to define the "applicable requirements" for the construction or modification covered by the minor NSR permit for purposes of what a permitting authority should incorporate into a title V permit, the first prong of the more expansive title V permit shield would only allow that compliance with the title V permit that includes the minor NSR permit to be deemed compliance with the terms and conditions of that minor NSR permit. Compliance with such a title V permit would not be deemed compliance with any major NSR applicability requirements. Therefore, compliance with the title V permit would not preclude an enforcement action alleging a violation of title I of the Act for failure to obtain a major NSR permit. However, if the permitting authority, "in acting on the [title V] permit application," makes a determination that major NSR requirements "are not applicable," to that construction or modification under the second prong of the more expansive permit shield provision, and the permit includes a summary of that non-applicability determination, that could provide a proper title V permit shield.[36] In such a case, the non-applicability determination would be part of the title V permit action and subject to judicial review under § 7661a(b)(6).

[36] In this case, UDAQ did not make a determination, in acting on the title V permit application, that PSD was not applicable requirement for the construction approved under the 1997 Approval Order.

Claim B: The Petitioner's Claim that "The Administrator Must Object to the Hunter Title V Renewal Permit Because It Includes 10-Year Plantwide Applicability Limits (PALs) for SO2 and NOx that Are Unlawful and Invalid."

Petitioner's Claim: The Petitioner claims that in 2008, "UDAQ issued an Approval Order for various projects that also established ten-year Plantwide Applicability Limits (PALs)[37] for SO_2 and NOx." Petition at 16. The Petitioner claims that these PALs for SO_2 and NOx "were unlawful, invalid and ineffective for . . . three main reasons . . . and must be removed from Hunter's title V permit." *Id.* at 17.

First, the Petitioner contends that UDAQ lacked the legal authority to impose 10-year PALs in 2008 because the EPA did not approve Utah's revised PSD rules that provide for 10-year PALs until 2011. *Id.* The Petitioner notes that the EPA, in comments on the draft Approval Order in 2008, informed UDAQ that "[u]ntil EPA approves Utah's NSR reform rules (including PAL provisions) into the SIP, PacifiCorp cannot rely on the ten-year PAL provisions in this permit to avoid federal enforcement of current SIP requirements for major NSR/PSD, in the event of a future major modification at the facility." *Id.* (quoting April 5, 2007, Letter from EPA to UDAQ). The Petitioner claims that states cannot unilaterally alter a SIP, and that SIPs cannot be considered legally amended until the EPA approves such revisions. *Id.* (citing multiple cases and 40 C.F.R. § 51.105). The Petitioner, therefore, concludes that UDAQ lacked the authority to establish the 10-year PALs. *Id.*

Second, the Petitioner claims that the PALs were not established in accordance with federal PAL rules or Utah's EPA-approved PSD SIP regulations. *Id.* at 18. Based on the premise asserted in Claim A—that PacifiCorp-Hunter should have been subject to BACT requirements for SO_2 and NOx for the 1997–1999 projects—the Petitioner asserts that the facility's actual emissions during the baseline period should have been lower than the baseline emissions upon which the SO_2 and NOx PALs were based. *Id.*

Third, the Petitioner claims that the federal and SIP PAL regulations required UDAQ to "specify a reduced PAL level(s) . . . to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit." *Id.* (citing 40 C.F.R. § 52.21(aa)(6), incorporated by reference into Utah Admin. Code R307-405-21(1), approved into the SIP at 76 Fed. Reg. 41712 (July 15, 2011)). The Petitioner claims that at the time the PAL permit was issued, UDAQ was aware that PacifiCorp-Hunter Units 1 and 2 would be subject to future NOx and SO_2 limitations under the regional haze plan requirements. *Id.* Accordingly, the Petitioner asserts that the PAL limits should have been reduced to reflect compliance with the regional haze requirements, to become effective on the compliance date of those requirements. *Id.* at 19.

The Petitioner further claims that the current title V renewal is the first time that the public has had an opportunity to comment on the incorporation of the PAL provisions into the title V

[37] As the Petitioner explains, "The establishment of a PAL for a particular pollutant allows a source to make physical or operational changes to existing emission units without having to individually review those changes for PSD applicability for the PAL pollutant as long as total Plantwide emissions remain under the level of the PAL." *Id.* at 16–17.

permit. *Id.* The Petitioner claims that the provisions were initially inappropriately incorporated into the title V permit after the initial title V permit had expired—which the Petitioner asserts was contrary to title V rules—and that this was done through administrative amendment procedures without adequate public notice—which the Petitioner also contends was unlawful. *Id.* at 20–22.

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

Relevant Legal Background

In accordance with part C of title I of the CAA, and EPA's implementing regulations, an existing major stationary source located in an area that is designated as attainment or unclassifiable for the NAAQS is required to obtain a PSD permit prior to beginning construction of a major modification. 42 U.S.C. §§ 7475, 7479(1) and (2)(C); 40 C.F.R. § 51.166; Utah Admin. Code R307-3.6-5.[38] The terms "Major Modification" and "Net Emissions Increase" were defined, in part, under the applicable PSD SIP at the time the 2008 Approval Order was issued as follows:

> "Major Modification" means any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act.
> ...

Utah Admin. Code R307-405-1. Further,

> "Net Emissions Increase" means the amount by which the sum of the following exceeds zero:
> 1. any increase in actual emissions from a particular physical change or change in method of operation at a source; and
> 2. any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable. ...

Utah Admin. Code R307-1-1.

The EPA finalized PAL provisions as part of the 2002 NSR reform rules.[39] PAL provisions were added to all of the major NSR rules, including the PSD rules in 40 C.F.R. § 51.166 and § 52.21. A PAL is an optional alternative major NSR applicability approach based on a pollutant-specific facility-wide emissions cap. Once a facility accepts a PAL, it may undertake modifications without the requirement to conduct a formal NSR applicability analysis (i.e., determining whether the project would result in a significant emissions increase and a significant net emissions increase), provided the facility's emissions will remain within the levels established in the PAL. A PAL can provide owners or operators of major stationary sources with the ability to manage facility-wide emissions without triggering major NSR. Once a PAL is issued, it has a

[38] Here and elsewhere in this response to the Petitioner's Claim B, references to the Utah Administrative Code are to those regulations, and codification, approved into the Utah SIP at the time of the subject Approval Order in 2008.
[39] 67 Fed. Reg. 80186, 80206 (December 31, 2002).

term of 10 years, and the source must submit an application for renewal of the PAL prior to its expiration. 40 C.F.R. § 52.21(aa)(4)(i)(f), (aa)(8)(i), (aa)(10).

In 2006, Utah incorporated by reference the revised federal PSD regulations (40 C.F.R. § 52.21) into its regulation R307-405, with some changes and submitted those rules to the EPA for SIP-approval in submittals dated September 15, 2006, October 1, 2007, and March 7, 2008.[40] Relevant portions of those rules, including the PAL provisions in R307-405-21, were approved by the EPA as part of the Utah SIP on July 15, 2011.[41]

Relevant Permit History

On November 27, 2007, PacifiCorp submitted a Notice of Intent (2007 Notice of Intent) to apply for authorization to complete various construction projects on Units 1, 2 and 3 at the PacifiCorp-Hunter plant, and to establish PALs for NOx and SO_2. A public notice was published in the Salt Lake Tribune on February 3, 2008, initiating a 30-day public comment period on the draft Approval Order and accompanying engineering evaluation. On March 13, 2008, UDAQ issued the final Approval Order DAQE-AN010237012-08 (2008 Approval Order) containing, among other things, the NOx and SO_2 PALs.

EPA's Analysis

As described above in Section II.B of this Order, the burden is on the Petitioner to identify a flaw in the title V permit such that it is not in compliance with the CAA. Thus, to the extent that a Petitioner is concerned with a defect related to an underlying applicable requirement (e.g., preconstruction permit or PAL), the Petitioner must demonstrate why such a purported flaw would cause the title V permit to be deficient.[42] Here, the Petitioner's claim is based on three alleged defects that it asserts affect the validity or federal enforceability of the SO_2 and NOx limits established in 2008 under PAL provisions incorporated into state law but not yet approved into the Utah SIP at the time. As explained in detail below, regardless of any purported deficiencies in the PALs, the Petitioner has not demonstrated how any such deficiencies resulted in a flaw in the current title V permit.

As an initial matter, the Petitioner has not demonstrated that the title V permit is missing any particular applicable requirement as a result of the alleged flaws with the SO_2 and NOx PALs. The Petitioner does not allege or otherwise demonstrate in Claim B that any particular projects would have triggered applicable NSR requirements but for reliance on the PAL, and, therefore, that the title V permit is missing applicable requirements. Although the Petitioner elsewhere alleges that some modifications of the PacifiCorp-Hunter facility triggered PSD requirements, *see* Claim D, below, the Petitioner has not demonstrated that the facility would have been subject to PSD requirements but for the inclusion of the PALs. Therefore, the Petitioner has not

---

[40] 74 Fed. Reg. 667 (January 7, 2009).
[41] 76 Fed. Reg. 41712 (July 15, 2011).
[42] *See In the Matter of Shell Deer Park*, Order on Petition Nos. VI-2014-04 and VI-2014-05 at 33 (September 24, 2015); *In the Matter of Consolidated Environmental Management, Inc. – Nucor Steel*, Order on Petition Nos. VI-2010-05, VI-2011-06, VI-2012-07 at 44 (January 30, 2014) (Nucor III Order).

demonstrated that the title V permit is missing any applicable requirements as a result of any purported deficiencies in the PALs.

Moreover, the Petitioner does not explain why, if its allegation that the PALs are "unlawful, invalid and ineffective" is true because the PALs were not federally-enforceable or incorrectly calculated, Petition at 17–19, the title V permit would be deficient. While the Petitioner claims that the PALs "must be removed from the title V permit," *id.* at 17; *see id.* at 36, the Petitioner includes no additional explanation as to why the PALs must be removed. Nor does the Petitioner provide any citation to any legal authority that would mandate this result. Even if the PALs based on enacted Utah regulations were not federally-enforceable because EPA had not yet approved those regulations into the Utah SIP at the time the 2008 Approval Order was issued, the Petitioner has not demonstrated that title V regulations mandate their "removal" from the title V permit. Although not cited by Petitioner, 40 C.F.R. § 70.6(b)(2) requires that "the permitting authority shall specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements."[43] This provision does not mandate "removing" the PAL provisions at issue from the title V permit if the Petitioner is correct that they are not federally-enforceable; instead, it would at most require that the provisions be designated as not federally enforceable. The Petition, however, does not allege such a deficiency in the title V permit.

Moreover, Utah cited regulations that were in the SIP as authority for the title V permit condition establishing the SO_2 and NOx emission limits at issue. 2016 Permit at 19, Condition II.B.1.i (citing Utah Admin. Code R307-401-8(1)(a)). Thus, even if the Petitioner is correct that UDAQ lacked the authority to establish PALs that would be effective as a federally-enforceable alternative to NSR applicability determination procedures because the 10-year PAL provisions of 40 C.F.R. § 52.21(aa) were not approved into Utah's SIP at the time the 2008 Approval Order was issued,[44] the Petitioner has not demonstrated that UDAQ lacked the independent authority

---

[43] Utah Admin. Code R307-415-6b(2) similarly requires "[A]pplicable requirements that are not required by the Act or implementing federal regulations shall be included in the permit but shall be specifically designated as being not federally enforceable under the Act and shall be designated as 'state requirements.'"

[44] The EPA acknowledges that in 2007, EPA Region 8 submitted a comment letter to UDAQ indicating that, "Until EPA approves Utah's NSR reform rules (including PAL provisions) into the SIP, PacifiCorp cannot rely on the ten-year PAL provisions in this permit to avoid Federal enforcement of current SIP requirements for major NSR/PSD, in the event of a future major modification at the facility." April 5, 2007, Letter from EPA to UDAQ, Re: EPA Region 8 Comments on Intent-to-Approve (Draft PSD Permit) for PacifiCorp's Hunter Power Plant, Enclosure at 5. Notably, this comment letter did not suggest that the Approval Order or the emission limits contained therein were deficient in their own right; it only indicated that the facility could not rely on the plantwide emission limits in the permit to avoid major NSR requirements for potential future actions that may occur at PacifiCorp-Hunter. Furthermore, the EPA notes that this regional comment letter was not a final agency position, and the EPA need not make any determination as to the validity of the PALs in order to respond to this title V petition, because the Petitioner has not demonstrated why any purported deficiency in the PAL permit resulted in a flaw in the title V permit. *See In the Matter of Appleton Coated, LLC*, Order on Petition Nos. V-2013-12 and V-2013-15 at 12 n.6 (October 14, 2016); *In the Matter of Chevron USA Inc. – 7Z Steam Plant*, Order on Petition No. IX-2016-8 at 8-9 (April 24, 2017). Moreover, the EPA notes that the PacifiCorp-Hunter PAL permit will expire on March 30, 2018. The title V permit clearly specifies the procedures by which PacifiCorp-Hunter will be required to apply for a renewal PAL permit. *See* 2016 Permit at 19, Condition II.B.1.i. Such a renewal permit will be issued according to, and must necessarily comply with, Utah's EPA-approved SIP regulations governing PAL permits (which, as described by Condition II.B.1.i, require compliance with 40 C.F.R. § 52.21(aa)(9)(i)–(v). This future PAL permit

under the referenced EPA-approved SIP rule to establish the SO_2 and NOx emission limits (and accompanying monitoring, recordkeeping, and reporting provisions) that are incorporated into the title V permit at Condition II.B.1.i. Similarly, the Petitioner has not demonstrated why, even accepting any purported deficiencies related to how the PAL levels were set or adjusted, this would result in the SO_2 and NOx emission limits being invalid under the SIP provision cited by Condition II.B.1.i. Therefore, the Petitioner has not demonstrated that these emissions limits could not be included in the title V permit as federally enforceable. Overall, the Petitioner has not demonstrated why any of the three alleged deficiencies related to the PALs established in 2008 have led to an objectionable flaw in the title V permit.

Regarding the Petitioner's claim that this is the first time the public has had an opportunity to comment on the incorporation of these facility-wide SO_2 and NOx emissions limits into the title V permit, and other concerns alleging that the prior incorporation of these terms was improperly processed, the Petitioner has not demonstrated that this resulted in a flaw in the 2016 title V permit. To the extent that these procedural issues concern any title V permit other than the 2016 Permit that is the subject of the Petition, those issues are outside of the scope of the 2016 title V permit proceeding, and, therefore, the current petition opportunity.[45] As explained in Section III.B of this Order, UDAQ did provide an opportunity for public comment on the 2016 Permit, consistent with 40 C.F.R. 70.7(h) and Utah Admin. Code R307-415-7i. The Petitioner took advantage of the opportunity to comment on the 2016 Permit, including the facility-wide SO_2 and NOx limits included in the 2016 Permit, submitting five pages of comments relevant to this Petition claim.[46]

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

Claim C: The Petitioner's Claim that "The Administrator Must Object to the Hunter Title V Renewal Permit Because It Fails to Include Approval Order Requirements, including BACT, for Unpermitted Modifications at Hunter Unit 1 in 2010."

Petitioner's Claim: The Petitioner claims that the PacifiCorp-Hunter title V permit is deficient because it does not identify, include, or assure compliance with BACT requirements for SO_2, NOx, and PM and other requirements reflected in the Approval Order rule in the Utah SIP. The Petitioner asserts these requirements should have been applicable to allegedly unpermitted modifications to the facility in 2010 (referred to in Claim C as the 2010 "modifications" or 2010 "projects"). Petition at 22, 26. The Petitioner also asserts that PacifiCorp-Hunter's operation without an Approval Order authorizing these modifications (and without the BACT requirements) has resulted in continuing violations of the Utah SIP, for which the title V permit must include a compliance schedule. *Id.* at 23, 27.

---

action may involve, among other things, a reevaluation of the PAL levels set by the permit. Utah's EPA-approved rules require that the public will have the opportunity to participate in this future proceeding, including to comment on any relevant outstanding concerns with the PAL renewal. *See* Utah Admin. Code R307-405-18.

[45] *See In the Matter of Hu Honua Bioenergy, LLC*, Order on Petition No. VI-2014-10 at 38–40 (September 14, 2016).

[46] *See* Petition Exhibit B, Sierra Club's Comments on the PacifiCorp-Hunter Power Plant DRAFT Title V Renewal Permit (Permit Number: 1500101002-Draft) at 74–78 (November 13, 2015) (Sierra Club Comments).

The Petitioner asserts that under the EPA-approved SIP rules that were applicable at the time of the 2010 modifications, prior to commencing a planned modification where there is a reasonable expectation of any emissions increase, the source must obtain an Approval Order imposing BACT limits and other requirements. *Id.* at 23 (citing the SIP Approval Order rule formerly codified at R307-1-3). The Petitioner acknowledges that PacifiCorp-Hunter applied for (in 2007) and ultimately received (in 2008) an Approval Order authorizing pollution control equipment and other identified projects at the facility. *Id.* at 24–25. However, the Petitioner claims that in addition to the projects specifically applied for and authorized by this Approval Order, the source undertook a number of additional modifications in 2010—including replacement of Unit 1's economizer, low temperature superheater, finishing superheater, pulverizer components, and various turbine upgrades—that "were not covered by the 2007 [Notice of Intent] or the 2008 Approval Order," and which, therefore, were "unpermitted." *Id.* at 25. The Petitioner asserts, and provides various arguments supporting its assertion, that it was reasonable to expect that these allegedly unpermitted projects would result in additional increases of emissions, and, as such, required an Approval Order. *Id.* at 26. The Petitioner challenges UDAQ's alleged failure to identify or include conditions in the title V permit reflecting SIP Approval Order permitting requirements (including BACT[47]), claiming that UDAQ must have "either erroneously relied on inapplicable and unlawful PALs or it simply ignored its Approval Order rules." *Id.*[48]

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

Relevant Legal Background

The air permitting rules in the approved SIP at the time of issuance of the 2008 Approval Order and the 2010 modifications were contained in Utah Admin. Code R307-1-3 *et seq.* Notice of Intent and Approval Order requirements, implementing in part the state's minor NSR program, were contained in Utah Admin. Code R307-1-3.1 (the Approval Order rule that the Petitioner references). The relevant requirements read, in part, as follows:

> Except for the exemptions listed herein, any person planning to construct a new installation which will or might reasonably be expected to become a source or an indirect source of air pollution or to make modifications or relocate an existing installation which will or might reasonably be expected to increase the amount or change the effect of, or the character of, air contaminants discharged, so that such installation may be expected to become a source or indirect source of air pollution, or any person planning to install an air cleaning device or other equipment intended to control emission of air contaminants

---

[47] The Petitioner references public comments, wherein the Petitioner claims to have demonstrated the current controls and limits would not constitute BACT. The Petitioner further asserts, "Although the Title V permit identifies the authority for the SO2, NOx, and PM Limits . . . as [BACT], the permit records for the Hunter Plant do not indicate that any recent evaluation of BACT was conducted for the Hunter units for any pollutant except CO in 2008." *Id.* at 27 n.112.

[48] The Petitioner's claim that the PALs were unlawful is discussed in Claim B above. The Petitioner claims that even lawfully established PALs may not be relied upon to exempt sources from the requirement to obtain an Approval Order. *Id.* at 24 (citing Utah Admin. Code R307-401-13 (2010) and a UDAQ memorandum from 2006). The Petitioner also claims that none of the exceptions contained in the Approval Order rule are applicable to the 2010 modifications, nor were any claimed. *Id.* at 24.

from a stationary source, shall submit to the Executive Secretary a notice of intent and receive an approval order prior to initiation of construction, modification or relocation.

Utah Admin. Code R307-1-3.1.1. Further,

> The Executive Secretary shall issue an approval order if he determines through plan review that the following conditions have been met:
>
> A. The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology except as otherwise provided in these regulations.

Utah Admin. Code R307-1-3.1.8.

The term "modification" is defined as "any planned change in a source which results in a potential increase of emission." Utah Admin. Code R307-1-1.

Relevant Permit History

As noted under the Relevant Permit History for Claim B, on March 13, 2008, UDAQ issued Approval Order DAQE-AN010237012-08 authorizing modifications to Units 1, 2 and 3 at the PacifiCorp-Hunter plant, including pollution control projects and other capital and operation and maintenance projects. Based on the 2007 Notice of Intent, the projects were scheduled to be completed by 2010, thus spanning multiple years.[49] PacifiCorp also indicated in its 2007 Notice of Intent that "[t]he projects listed are based on current plans which may be refined as overhaul schedules and equipment status change. As PacifiCorp further refines the project lists, that information will be provided to the Utah Division of Air Quality."[50] UDAQ acknowledged in its 2008 Modified Source Plan review that "[t]he replacement, addition or upgrade of existing emissions controls will result in a potential increase of some air pollutant emissions, necessitating the issuance of an approval order pursuant to [Utah Admin. Code] 307-401."[51]

In a letter from to UDAQ dated December 18, 2009, PacifiCorp identified that there would be a delay in the schedule for installation of pollution controls on Units 1 and 2.[52] In addition to the

---

[49] Specific projects identified in the 2007 Notice of Intent included: 1) Installation of low NOx burners and overfire air systems on Units 1, 2 and 3; 2) Upgrade of FGD systems on Units 1, 2 and 3 to achieve 90 percent control via elimination of bypass; and 3) Replacement of electrostatic precipitators with baghouses on Units 1 and 2. Additionally, a number of capital and operation and maintenance (O&M) projects were identified on Units 1–3 that were proposed to be completed contemporaneously with the pollution control projects.
[50] 2007 Notice of Intent at 2-1.
[51] UDAQ Modified Source Plan Review, RE: Installation of Pollution Control Equipment, Establishing Plantwide Applicability Limitations and Approval Orders Consolidation at 24 (January 25, 2008) (Ex. 38 to Sierra Club Comment Letter) (2008 Modified Source Plan Review).
[52] Specifically, PacifiCorp indicated that the completion of pollution controls on Unit 2 would be delayed one year and the final completion of pollution controls on Unit 1 would be delayed until 2014. Letter from William K. Lawson, PacifiCorp, to Ms. Cheryl Heying, UDAQ RE: Status of Hunter Plant's Pollution Control Equipment and Capital and O&M Projects (December 18, 2009) (Ex. 39 to Sierra Club Comment Letter) (December 2009 PacifiCorp Letter). To address any potential emissions increases associated with the deferral of the Unit 1 pollution control projects without deferring the contemporaneous capital projects at that unit, PacifiCorp proposed that, with

changes to the project schedule, PacifiCorp indicated that it was moving forward with other contemporaneous capital projects authorized by the 2008 Approval Order and that it would perform a series of Unit 1 "capital and operations and maintenance projects" in 2010–2011, not specifically identified in the 2007 Notice of Intent.[53] PacifiCorp stated that "[t]he turbine upgrades will take advantage of technological improvements to increase the efficiency of the steam turbine to provide increased power to the generator without increasing the heat input from the boilers."[54]

UDAQ responded to PacifiCorp's update on the 2008 Approval Order projects in a letter dated February 1, 2010. UDAQ found that PacifiCorp's proposal was "consistent with the requirements of [the 2008 Approval Order]."[55] UDAQ also concluded that a permit extension was not necessary because, in part, "PacifiCorp's [Approval Order] does not specify any order in which construction must proceed . . . ."[56]

EPA's Analysis

The Petitioner's claim relies upon the supposition that the changes to Unit 1 undertaken by PacifiCorp in 2010 were "unpermitted" because they "were not covered by the 2007 [Notice of Intent] or the 2008 Approval Order." However, the Petitioner has not demonstrated that the 2010 modifications were not authorized by the 2008 Approval Order. In fact, as explained above, it is clear from the permit record and relevant correspondence that UDAQ considered the projects on Unit 1 identified in PacifiCorp's 2010 letter to be authorized under the 2008 Approval Order. Indeed, the 2008 Approval Order authorized numerous different modifications and control projects at the PacifiCorp-Hunter plant "installations," projected to be completed over a period of years. The facility said the following in its initial 2007 Notice of Intent: "As PacifiCorp further refines the project lists, that information will be provided to the Utah Divisions of Air Quality."[57] Moreover, with respect to the 2010 modifications, UDAQ explicitly found that PacifiCorp's proposal was "consistent with the requirements of [the 2008 Approval Order]," and noted that an extension to the initial 2008 Approval Order was not necessary to accommodate the proposed

---

the exception of NOx and SO_2 that were covered by PALs, it would follow the requirements of 40 C.F.R § 52.21(r)(6)(iv) and submit annual reports to UDAQ until completion of the pollution control projects. *Id.* UDAQ determined that this proposal was "consistent with . . . 40 C.F.R. § 52.21 (r), as incorporated into the Utah Air Quality Rules at Utah Admin. Code R307-401-19." Letter from M. Cheryl Heying, UDAQ to William K. Lawson, PacifiCorp. RE: Status of Hunter Plant's Pollution Control Equipment and Capital and O&M Projects, DAQE-GN0102370018-10 (February 1, 2010) (Ex. 40 to Sierra Club Comment Letter) (February 2010 UDAQ Letter). While UDAQ found PacifiCorp's proposal to submit annual reports pursuant to 40 C.F.R § 52.21 (r)(6)(iv) an acceptable method to demonstrated continued compliance, it also required the submittal of semiannual project status reports to "assure the agency that no increase in emissions is taking place, and that the construction is proceeding in a timely manner." *Id.*

[53] December 2009 PacifiCorp Letter. The changes to Unit 1 described by PacifiCorp included turbine upgrades and replacement of the economizer, low temperature superheater, finishing superheater, and pulverizer components.

[54] *Id.*

[55] February 2010 UDAQ Letter.

[56] *Id.*

[57] 2007 Notice of Intent at 2-1.

modifications.[58] Overall, the Petitioner has failed to demonstrate that the 2010 modifications were unpermitted.

The Petitioner appears to suggest that these changes were required to be evaluated as a separate modification under the applicable Approval Order rule, rather than in aggregate with the other changes to the PacifiCorp-Hunter plant authorized by the 2008 Approval Order. However, the Petitioner has not demonstrated that there was any requirement in the applicable SIP that limited UDAQ's discretion to determine the construction, modification, relocation and pollution control installation activities that should or could be aggregated for the purposes of meeting the Approval Order rule requirements.[59] The Petitioner has not demonstrated that UDAQ's consideration and authorization of the 2010 projects as part of the broad set of changes covered by the 2008 Approval Order was prohibited by the SIP or otherwise unreasonable. Thus, the Petitioner has not demonstrated that the 2010 projects were "unpermitted," or that the 2010 projects warranted a separate Approval Order.

Even assuming for purposes of argument that the Petitioner's premise that the 2010 projects should have been evaluated and permitted separately under the Utah Approval Order rule is valid, the Petitioner has not demonstrated that UDAQ should have determined that those projects "will or might reasonably be expected to increase the amount or change the effect of, or the character of, air contaminants discharged..." thus requiring an approval order under the SIP.[60] The Petitioner stated:

> The unpermitted 2010 Unit 1 work, individually or collectively, had the potential to result in increases of emissions of air contaminants, including, but not limited to, SO2, NOx, and PM from Hunter Unit 1. It was reasonable to expect that this work might increase those air contaminants due to an expected increase in the maximum hourly fuel burning capacity of Unit 1, an increase in its operating capacity factor, and/or an increase in the total number of hours in a year that Unit 1 could operate as a consequence of improvements in reliability and/or availability and/or improvements in efficiency, which could lead to an increase in dispatching of the unit.

Petition at 26. Other than the alleged increase in the heat input capacity of Unit 1—which, as described in the EPA's response to Claim D, the Petitioner has not adequately demonstrated—the Petitioner's conclusion that that the projects would have triggered the requirement for an approval order are based on speculative and unsubstantiated assertions.[61] As the EPA has

[58] In the February 2010 UDAQ Letter to PacifiCorp, UDAQ stated: "Since the capital improvements and pollution control equipment are related to existing facilities, the agency considers these activities to be site specific. Moreover, since PacifiCorp's Approval Order does not specify any order in which construction must proceed, the Executive Secretary has reviewed your letters in terms of whether the commence construction requirement has been satisfied., regardless of whether the construction is for capital improvements or for pollution control equipment."

[59] *See* Utah Admin. Code R307-1-3.1. The plain language of this provision does not explicitly limit or define the scope of the construction, modification, relocation and pollution control installation activities that could be considered in aggregate for the purposes of approval order applicability and requirements.

[60] *Id.*

[61] To the extent that the public comments incorporated into the Petition contained more detailed support for these assertions, the EPA notes that these arguments are similarly speculative and do not demonstrate that the 2010

previously stated, vague or general assertions are inadequate to demonstrate a flaw in a title V permit.[62]

Furthermore, the Petitioner provided no analysis of the 2008 Approval Order record indicating a flaw in any BACT requirements applied to Unit 1. As the Petitioner acknowledges, the title V permit identifies the authority for the SO_2, NOx, and PM limits on Unit 1 as the limits selected as BACT in the 2008 Approval Order.[63] The Petitioner does not explain why the 2010 projects, which were modifications to an existing unit (Unit 1) that UDAQ considered authorized by the 2008 Approval Order, would require different BACT controls and limits than the BACT that was established for that existing unit in the 2008 Approval Order. The Petitioner claims in a footnote that its public comments purportedly "demonstrated that the currently [sic] pollution controls and/or emission limits of the Title V permit would not constitute BACT." For the reasons discussed in response to Claim A, the title V process is not the appropriate place for Petitioner to address its disagreements with UDAQ's prior determination of the conditions in a preconstruction permit. Even if it were, the Petition does not substantiate the assertion in this footnote that the limits do not constitute BACT under the Utah approval order regulations for the 2010 modifications covered by the 2008 Approval Order. Therefore, the Petitioner has not demonstrated that, even assuming the 2010 changes required additional permitting, the BACT limits applied to Unit 1 in the title V permit are not appropriate for the 2010 modification to which they apply under the 2008 Approval Order. Overall, the Petitioner has not demonstrated that the title V permit is deficient with respect to any applicable requirements associated with the SIP Approval Order rules and the 2010 modifications.[64]

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

---

projects triggered the requirement for an additional Approval Order. For example, the public comments, which rely in part on examples from purportedly similar projects at other sources and "turbine vendor literature," allege that the 2010 projects "might increase the amount of" SO2, NOx, and PM, "could lead to an increase in dispatching of the unit," "are known to have propensity to result in an increase in annual emissions," "could very well have required additional heat input," etc. Sierra Club Comments at 65–66.

[62] *See supra* note 8 and accompanying text.

[63] *See* 2016 Permit conditions II.B.2.a (PM limit, citing, in part, "R307-401-8(1)(a) (BACT)" as authority), II.B.2.b & c (NOx limits, same), II.B.2.d (SO2 limit, same). Moreover, as noted above, UDAQ in its 2008 Modified Source Plan Review acknowledged the BACT requirements applicable to the Approval Order, and concluded that BACT for the group of projects falling within the scope of the 2008 Approval Order—which would result in a "substantial reduction in emissions" across all projects—would be satisfied by the controls that the source was seeking approval to install. *See* 2008 Modified Source Plan Review at 35.

[64] Because the Petitioner has not demonstrated that the title V permit is missing any applicable requirements, or that the source was otherwise not in compliance with any applicable requirements at the time of title V permit issuance, it has not demonstrated that a compliance schedule is warranted. *See* 42 U.S.C. § 7661c(a); 40 C.F.R. §§ 70.5(c)(8) & 70.6(c)(3); Utah Admin. Code R307-415-5c(8)(c)(iii); 307-415-6c(3); *see also, e.g.*, *In the Matter of CEMEX, Inc., Lyons Cement Plant*, Order on Petition No. VIII-2008-01 at 7 (April 20, 2009).

Claim D: The Petitioner's Claim that "The Administrator Must Object to the Hunter Title V Permit Because It Fails to Include PSD Requirements for NOx including BACT for the 2010 Projects at Hunter Unit 1."

Petitioner's Claim: The Petitioner asserts that the 2010 projects discussed in Claim C above should have triggered PSD requirements, including BACT, for NOx. Petition at 28.[65] The Petitioner asserts that the EPA must object to the title V permit because it does not include these PSD requirements, and because the 2016 Permit does not include a schedule of compliance to ensure that these requirements are ultimately incorporated into the title V permit. *Id.* at 30.

The Petitioner further claims that, under the SIP provisions applicable at the time of the 2010 projects,[66] the 2010 projects should have triggered PSD. The Petitioner claims that a 2007 Notice of Intent reflects a 50 MMBtu/hour heat input increase, which the Petitioner asserts "was likely related to the HP/IP/LP turbine upgrades and possibly also the boiler component replacement projects completed at Hunter Unit 1 in 2010." Petition at 28–29. The Petitioner claims that its public comments demonstrate that this alleged 50 MMBtu/hour heat input increase should have been projected to result in a significant emissions increase of NOx as well as a significant net emissions increase of NOx, thereby triggering PSD requirements for NOx. *Id.*[67]

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

Relevant Legal Background

Refer to the Relevant Legal Background for Claim B.

Relevant Permit History

Refer to the Relevant Permit History for Claims B and C.

---

[65] The Petitioner's argument in Claim D that the 2010 projects triggered PSD for NOx is based on the "[a]ssum[ption] that the NOx PAL was not validly established," as discussed in Claim B. *Id.* at 28. The Petitioner argues that, because the NOx PAL was not lawfully established, the NOx PAL should not have been relied upon to exempt the 2010 projects at PacifiCorp-Hunter Unit 1 from PSD requirements. *Id.* at 29. The Petitioner also claims that various turbine upgrades and boiler component replacements should not qualify for routine maintenance, repair, and replacement (RMRR) exemptions, challenging a contention by the facility in a 2009 letter that "many" of the 2010 projects were considered RMRR. *Id.* at 28.

[66] The Petitioner asserts that the applicable SIP requirements related to PSD applicability were based on the EPA's 1992 "WEPCO Rule," and required a comparison of pre-project actual emissions to post-project representative actual emissions. *Id.* at 28 (citations omitted).

[67] Specifically, after claiming that the alleged heat input increase should have been projected to result in a significant emissions increase, the Petitioner claims that project would have also involved a significant net emissions increase because any emission reductions associated with the control projects authorized by the 2008 Approval Order would not have been creditable for netting. *Id.* at 29.

EPA's Analysis

As described above in Claim B, PSD requirements apply to, among other things, "major modifications," defined as "any physical change or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Clean Air Act." Utah Admin. Code R307-405-1. Necessarily, this analysis requires a determination of the set of related activities that must be evaluated either together or separately as the "physical change or change in the method of operation." In Claim D, the Petitioner appears to argue that the 2010 projects discussed in Claim C[68] were required to be evaluated as a separate "physical change or change in the method of operation" of the PacifiCorp-Hunter plant for purposes of determining PSD applicability under the applicable SIP regulations, rather than considered in aggregate with the other changes authorized by the 2008 Approval Order.[69] However, as discussed above, the Petitioner has not demonstrated any deficiency with respect to how UDAQ evaluated the projects authorized in the 2008 Approval Order, including whether and how UDAQ determined that the 2010 projects did not trigger PSD.

As discussed in Claim C, the permit record and relevant correspondence shows that UDAQ considered the modifications to Unit 1 identified in PacifiCorp's 2010 letter to be activities authorized under the 2008 Approval Order. In any case, the Petitioner did not demonstrate that there was any requirement in the applicable SIP that limited UDAQ's discretion to determine the "physical change[s] or change[s] in the method of operation" that in aggregate constitute a project that must be evaluated to determine PSD applicability.[70] The Petitioner did not claim that the aggregation of projects initially authorized by the 2008 Approval Order was flawed nor did it demonstrate that the changes identified in PacifiCorp's 2010 update letter could not, consistent with the applicable SIP and EPA policy,[71] be considered in the aggregate with other changes authorized by the 2008 Approval Order. Furthermore, the Petitioner provided no analysis of the 2008 Approval Order record indicating a flaw in the emissions increase and PSD applicability conclusions resulting from the 2010 changes to Unit 1.

Even assuming for the sake of argument that the changes to Unit 1 described in PacifiCorp's 2009 letter should have been considered as a separate "physical change or change in the method

---

[68] Note that the 2010 "projects" discussed in Claim D refer to the same activities as the 2010 "modifications" or "projects" introduced in Claim C.

[69] Similar to the Petitioner's arguments in Claim C relating to Approval Order Rule requirements, Claim D is based on the premise that the 2010 projects were either not permitted under the 2008 Approval Order or should have been evaluated separately from the other projects authorized by the Approval Order for purposes of determining PSD applicability.

[70] Utah Admin. Code R307-405-1 (definition of "major modification" for purposes of PSD applicability).

[71] The EPA's policy on aggregation outlines an approach relying upon case-specific factors (e.g., timing, funding, and the company's own records) and the relationship between nominally-separate changes, and does not preclude the aggregation of multiple physical or operational changes when such changes taken together can be reasonably viewed as sufficiently related to be a single project even if individually or smaller groupings also could be viewed as physical or operational changes. For a collection of prior EPA memoranda relevant in determining whether projects should be aggregated, see 75 Fed. Reg. 19567, 19570–71 (April 15, 2010). While the policy discussion in this reconsideration notice does not represent a final agency position without further action by the agency, the numerous memoranda cited in this notice stand for themselves as examples of our historic approach to aggregation.

of operation," and would not have been exempt routine maintenance repair and replacement,[72] and granting the Petitioner's premise that PSD applicability should not have been based on the PALs in the 2008 Approval Order, the Petitioner has not demonstrated that PSD should have applied to the 2010 projects. Specifically, the Petitioner's emissions increase analysis and PSD applicability conclusion are deficient. The Petitioner's argument that PSD should have applied to the 2010 projects rests on a purported 50 MMBtu/hour heat input increase, which the Petitioner claims "was *likely* related to the HP/IP/LP turbine upgrades and *possibly* also the boiler component replacement projects completed at Hunter Unit 1 in 2010." Petition at 28–29 (emphasis added). This alleged 50 MMBtu/hour heat input increase on Unit 1 is based on a comparison of the "maximum demonstrated heat input" reported in a 1997 Notice of Intent to the "maximum nominal heat input rating" reported in a July 19, 2007, updated Notice of Intent. As an initial matter, the EPA notes that the maximum nominal heat input rating cited by the Petitioner is associated with the list of projects in the July 19, 2007, updated Notice of Intent, not the 2010 projects. Therefore, the Petitioner has not provided any direct evidence that the 2010 projects themselves resulted in an increase in the heat rate input that could increase emissions.

However, even the Petitioner's evaluation of a potential increase in heat input from the 2010 projects is flawed. The comparison of *demonstrated* heat input (based on production data and heat and material balance) to the *nominal* heat input rating is a comparison of heat input capacity values based on different estimation approaches. It does not follow that had the comparison been made using a consistent approach, i.e., demonstrated capacity before and after the projects or nominal capacity before and after the projects, the same result or conclusion would be reached. Therefore, the Petitioner's analysis cannot be relied upon in concluding that the 2010 projects resulted in a 50 MMBtu/hour heat input capacity increase on Unit 1. Moreover, PacifiCorp stated in its 2009 letter describing the 2010 projects on Unit 1 that "[t]hese projects will increase the thermal efficiency of the steam turbine and will not result in a heat input increase." Overall, the Petitioner did not demonstrate that the 2010 projects resulted in a heat input capacity increase on Unit 1. Therefore, the Petitioner did not demonstrate that those projects, if considered separately from other activities authorized by the 2008 Approval Order and if analyzed under the SIP rules that the Petitioner asserts were applicable, would have resulted in a significant emissions increase or a significant net emissions increase of NOx,[73] triggering PSD requirements. Accordingly, the Petitioner has not demonstrated that the PacifiCorp-Hunter title V permit is missing any applicable requirement.[74]

---

[72] PacifiCorp indicated, it its December 2009 Letter, that "[m]any of these projects are considered like-kind replacements and routine maintenance, repair and replacement projects…" The Petitioner cites this in Claim D, and presents arguments to support its position that the projects did not qualify as RMRR. However, there is no evidence that PacifiCorp or UDAQ relied upon the RMRR exemption in determining PSD was not applicable to the 2010 projects on Unit 1. Therefore, these arguments concerning RMRR are not relevant.

[73] Because the Petitioner has not demonstrated that a significant emissions increase occurred, it necessarily follows that the Petitioner has not demonstrated that the 2010 projects, considered separately, constituted a major modification, irrespective of the Petitioner's assertions regarding the creditability of certain emission reductions. In addition, it does not appear that either PacifiCorp or UDAQ relied on a contemporaneous net emissions increase analysis in determining PSD applicability with respect to the 2010 projects, so the Petitioner's argument is not relevant.

[74] As noted above, because the Petitioner has not demonstrated that the title V permit is missing any applicable requirements, or that the source was otherwise not in compliance with any applicable requirements at the time of title V permit issuance, it has not demonstrated that a compliance schedule is warranted. *See* 42 U.S.C. § 7661c(a);

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

Claim E: The Petitioner's Claim that "The Administrator Must Object to the Hunter Title V Renewal Permit Because UDAQ has Failed to Consider and Respond to Sierra Club's Comments."

Petitioner's Claim: The Petitioner asserts that UDAQ's RTC was deficient with respect to comments that raised the issues discussed above.[75] The Petitioner claims that UDAQ was "required by law" to substantively respond to public comments, and that UDAQ's failure to do so compels an EPA objection. Petition at 30–31 (citing Utah Admin. Code R307-415-7i). The Petitioner claims that UDAQ did not consider or respond to the issues raised in public comments, but rather rejected the comments out of hand, claiming that they were "not applicable to this Title V renewal action" but instead "pertain to the underlying requirements that are now simply incorporated into the Title V operating permit." *Id.* at 30 (quoting RTC at 3).

The Petitioner claims that, contrary to UDAQ's assertions in title V renewal permits (as opposed to permit modifications), all aspects of the permit are subject to review. *Id.* at 32 (citing *In the Matter of Wisconsin Public Service Corporation – Weston Generating Station*, Order on Petition No. V-2006-4 at 5 (December 19, 2007)). The Petitioner asserts that "[t]his broad scope of review necessarily invites comments challenging the erroneous omission of applicable requirements from Title V renewal permits, and comfortably encompasses all the issues raised in Sierra Club's comments and this Petition." *Id.* at 32–33. The Petitioner claims that "in the context of a Title V renewal permit, prior permitting actions that are relevant to the existence or application of applicable requirements are within the scope of permit review." *Id.* at 20 n.81.[76]

The Petitioner additionally challenges UDAQ's assertion that some of the comments related to compliance and were, therefore, an enforcement matter beyond the scope of this permitting action. The Petitioner asserts that many issues in the title V process could be viewed as broadly relating to compliance and enforcement, but nothing in the CAA or title V regulations suggests that such issues are excluded from review in the title V process. *Id.* at 34. The Petitioner also claims that no potential jurisdictional bar exists that would prohibit the Petitioner from pursuing these claims here. *Id.* at 33–34.

The Petitioner claims that the EPA has previously objected to a title V permit featuring the same types of alleged shortcomings—namely, the failure of a state agency to respond to public comments concerning PSD applicability for previous modifications—and suggests that the EPA must object here for the same reasons. *Id.* at 31 (citing *In the Matter of Tennessee Valley Authority, Paradise Fossil Fuel Plant*, Order on Petition No. IV-2007-3 at 5 (July 13, 2009) (*2009 TVA Paradise Order*). Specifically, the Petitioner notes that in the TVA Paradise Order,

---

40 C.F.R. §§ 70.5(c)(8) & 70.6(c)(3); Utah Admin. Code R307-415-5c(8)(c)(iii); 307-415-6c(3); *see also, e.g.*, *In the Matter of CEMEX, Inc., Lyons Cement Plant*, Order on Petition No. VIII-2008-01 at 7 (April 20, 2009).

[75] The Petitioner also briefly raised challenges to UDAQ's RTC within each of the claims discussed above, to which the EPA is collectively responding in this claim. *See* Petition at 15–16 (Claim A); 19 (Claim B); 27 (Claim C), 29 (Claim D).

[76] With respect to public comments concerning PALs, the Petitioner also claims that these comments went well beyond questioning a past permitting action, because the PALs define the mechanism for whether PSD is triggered for SO2 or NOx in the future (through 2018). *Id.* at 19, 22.

the EPA objected because the state's failure to respond to a significant comment "may have resulted in one or more deficiencies in the permit." *Id.* (quoting *2009 TVA Paradise Order* at 6)

EPA's Response: For the following reasons, the EPA denies the Petitioner's request for an objection on this claim.

UDAQ's Response

UDAQ responded to all of the Petitioner's NSR-related comments, including those raised in Claims A, B, C, and D of the Petition, by stating that: (1) those claims pertain to compliance, previous NSR permitting, and the Utah SIP; (2) compliance is an enforcement matter for UDAQ and is not addressed in this permitting action; (3) any concerns regarding previous permits should have been raised during public comments at the time those permitting actions took place, and any concerns regarding the SIP should have been raised during public comment period for the applicable rulemaking actions by the Utah Air Quality Board; and (4) the renewal title V permit is simply incorporating applicable requirements, and thus the comments are not applicable to the 2016 title V permit renewal action. *See* RTC at 2–3.

Additionally, regarding the Petitioner's comments that the PALs should have been adjusted to reflect regional haze requirements, UDAQ stated that the title V renewal permit is based on the April 6, 2015, Approval Order and applicable state and federal rules, and that the comments are not applicable to the title V renewal permitting action. *Id.* at 4. Finally, regarding the Petitioner's comments on the process UDAQ used to incorporate the 2008 Approval Order (including the PALs) into the title V permit, UDAQ responded that whether UDAQ properly followed the permitting procedures in previous permitting actions is not at issue in this proceeding and thus the comments are not applicable to the title V renewal action. *Id.* at 5–6.

EPA's Analysis

As described above, in the EPA's response to Claim A, the Petitioner has not demonstrated that UDAQ improperly incorporated the terms and conditions of the 1997 Approval Order into the title V permit for PacifiCorp-Hunter. Under the interpretation of the EPA's part 70 regulations in this Order, the terms and conditions of that minor NSR permit were incorporated without further review as part of the title V permitting process. This is reflected in UDAQ's response to comments when they explain that "[a]ny concerns regarding previous permits should have been raised during public comments at the time those permitting actions took place . . . [A] Title V operating permit does not impose any new requirements but simply brings together all existing requirements from pervious [sic] permitting actions to aid enforcement . . . ." RTC 2–3. This is consistent with the EPA's interpretation of the requirements of part 70. Therefore, with regards to the issues raised by the Petitioners in Claim A, the Petition does not demonstrate that UDAQ's RTC was inadequate.

As described above, in the EPA's response to Claim B, the Petitioner has not demonstrated that the title V permit for PacifiCorp-Hunter is flawed because of the inclusion of the SO_2 and NO_X PALs established in the 2008 Approval Order. To the extent that the Petitioner's claim is that UDAQ lacked the authority to establish PALs that would be effective as a federally enforceable alternative to NSR applicability determination procedures, the Petitioner has not pointed to any particular inappropriate use of these PALs. The use of PALs as an alternative to other NSR applicability determination procedures in any future permitting action is a forward looking compliance issue. The Petitioner has not demonstrated that UDAQ was unreasonable in responding that "[c]ompliance is an enforcement matter for UDAQ and is not addressed in this permitting action." RTC at 2. Therefore, to the extent that Claim B raised these issues, the Petition does not demonstrate that UDAQ's RTC was inadequate.

To the extent that UDAQ did not substantively address the issues implicated in Claims C and D, the Petitioner has not demonstrated how this violated any title V permitting requirement or otherwise resulted in a flaw in the permit.[77] As described above, in the EPA's response to Claims C and D, the Petition has not demonstrated that the 2016 Permit fails to include applicable requirements or is inconsistent with part 70. Therefore, the Petitioner has not demonstrated in Claim E that the title V permit is "not . . . in compliance with applicable requirements" or the requirements of part 70. 40 C.F.R. § 70.8(c)(1); *see* 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d).

For the foregoing reasons, the EPA denies the Petitioner's request for an objection on this claim.

V. CONCLUSION

For the reasons set forth above and pursuant to CAA § 505(b)(2) and 40 C.F.R. § 70.8(d), I hereby deny the Petition as described above.

Dated: OCT 16 2017

E. Scott Pruitt,
Administrator.

[77] The Petitioner claims that UDAQ was required by law to "substantively respond" to the Petitioner's comments by pointing to Utah Admin. Code R307-415-7i. This provision details the public participation requirements for UDAQ's issuance of title V operating permits. However, the Petition does not include any legal analysis of this provision to demonstrate that UDAQ was required to "substantively respond" to the Petitioner's comments. The EPA notes that while this provision requires UDAQ to provide notice to the public and affected states, R307-415-7i(1)-(3), and to "keep a record of the commenters and also of the issues raised during the public participation process," R307-415-7i(5), this provision does not appear to require UDAQ to "substantively respond" to such comments or issues raised.

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT
100 EAST FIFTH STREET, ROOM 540
POTTER STEWART U.S. COURTHOUSE
CINCINNATI, OHIO 45202-3988

Deborah S. Hunt
Clerk

Tel. (513) 564-7000
www.ca6.uscourts.gov

Filed: January 10, 2017

Mr. Thomas A. Benson
U.S. Department of Justice
Environment & Natural Resources Division
P.O. Box 7611
Washington, DC 20044

Mr. Mark B. Bierbower
Mr. F. William Brownell
Mr. Makram Bassam Jaber
Hunton & Williams
2200 Pennsylvania Avenue, N.W.
Washington, DC 20037

Mr. Shannon W. Fisk
Earthjustice, 1617 John F. Kennedy Boulevard, Suite 1675
Philadelphia, PA 19103

Mr. Harry Margerum Johnson III
Mr. George Peter Sibley III
Hunton & Williams
951 E. Byrd Street
Richmond, VA 23219

Mr. Matthew J. Lund
Pepper Hamilton
4000 Town Center, Suite 1800
Southfield, MI 48075

Mr. Brent Rosser
Hunton & Williams
101 S. Tryon Street, Suite 3500
Charlotte, NC 28280

Mr. Michael J. Solo Jr.
DTE Energy, One Energy Plaza, 688 WCB
Detroit, MI 48226

Ms. Mary Melissa Whittle
Earthjustice
3904 Bonnell Drive
Austin, TX 78731

Re: Case Nos. 14-2274/2275, *USA v. DTE Energy Company, et al*
Originating Case No. : 2:10-cv-13101

Dear Counsel,

The court today announced its decision in the above-styled cases.

Enclosed is a copy of the court's opinion together with the judgment which has been entered in conformity with Rule 36, Federal Rules of Appellate Procedure.

Yours very truly,

Deborah S. Hunt, Clerk

Cathryn Lovely
Deputy Clerk

cc: Mr. David J. Weaver

Enclosures

Mandate to issue.

RECOMMENDED FOR FULL-TEXT PUBLICATION
Pursuant to Sixth Circuit I.O.P. 32.1(b)

File Name: 17a0006p.06

UNITED STATES COURT OF APPEALS

FOR THE SIXTH CIRCUIT

UNITED STATES OF AMERICA (14-2274), *Plaintiff-Appellant*, SIERRA CLUB (14-2275), *Intervenor Plaintiff-Appellant*, *v.* DTE ENERGY COMPANY and DETROIT EDISON COMPANY, *Defendants-Appellees*.	Nos. 14-2274/2275

Appeal from the United States District Court
for the Eastern District of Michigan at Detroit.
No. 2:10-cv-13101—Bernard A. Friedman, District Judge.

Argued: December 10, 2015

Decided and Filed: January 10, 2017

Before:BATCHELDER, DAUGHTREY, and ROGERS, Circuit Judges.

COUNSEL

ARGUED: Thomas A. Benson, UNITED STATES DEPARTMENT OF JUSTICE, Washington, D.C., for Federal Appellant. Mary Whittle, EARTHJUSTICE, Philadelphia, Pennsylvania, for Appellant Sierra Club. F. William Brownell, HUNTON & WILLIAMS LLP, Washington, D.C., for Appellees. **ON BRIEF:** Thomas A. Benson, UNITED STATES DEPARTMENT OF JUSTICE, Washington, D.C., for Federal Appellant. Mary Whittle, Shannon Fisk, EARTHJUSTICE, Philadelphia, Pennsylvania, for Appellant Sierra Club. F. William Brownell, Mark B. Bierbower, Makram B. Jaber, HUNTON & WILLIAMS LLP, Washington, D.C., Brent A. Rosser, HUNTON & WILLIAMS LLP, Charlotte, North Carolina, Harry M. Johnson III, George P. Sibley III, HUNTON & WILLIAMS LLP, Richmond, Virginia, Michael J. Solo, DTE ENERGY COMPANY, Detroit, Michigan, for Appellees.

DAUGHTREY, J., delivered the opinion in which BATCHELDER, J., joined in the result. BATCHELDER, J. (pp. 9–14), delivered a separate opinion concurring in the judgment. ROGERS, J. (pp. 15–29), delivered a separate dissenting opinion.

OPINION

MARTHA CRAIG DAUGHTREY, Circuit Judge. This case is before us for a second time, following an order of remand in *United States v. DTE Energy Co.* (*DTE I*), 711 F.3d 643 (6th Cir. 2013). As we noted there, regulations under the Clean Air Act require a utility seeking to modify a source of air pollutants to "make a preconstruction projection of whether and to what extent emissions from the source will increase following construction." *Id.* at 644. This projection then "determines whether the project constitutes a 'major modification' and thus requires a permit" prior to construction, as part of the Act's New Source Review (NSR) program. *Id.*; *see also* 42 U.S.C. §§ 7475, 7503; 40 C.F.R. § 52.21. The NSR regulations require an operator to "consider all relevant information" when estimating its post-project actual emissions but allow for the exclusion of any emissions "that an existing unit could have accommodated during the [baseline period] . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(a) and (c). An operator must document and explain its decision to exclude emissions from its projection as resulting from future "demand growth" and provide such information to the EPA or to the designated state regulatory agency. 40 C.F.R. § 52.21(r)(6)(i)–(ii).

Defendants DTE Energy Co. and its subsidiary, Detroit Edison Co. (collectively DTE), own and operate the largest coal-fired power plant in Michigan at their facility in Monroe, where, in 2010, DTE undertook a three-month-long overhaul of Unit 2 costing $65 million. On the day before it began construction, DTE submitted a notification to the Michigan Department of Environmental Quality stating that DTE predicted an increase in post-construction emissions 100 times greater than the minimum necessary to constitute a "major modification" and require a preconstruction permit. DTE initially characterized the projects as routine maintenance, repair, and replacement activities, a designation that, if accurate, would exempt the projects from triggering NSR.[1] *See New York v. U.S. Envtl. Prot. Agency*, 443 F.3d 880, 883–84 (D.C. Cir. 2006). DTE also informed the state agency that it had excluded the entire predicted emissions increase from its projections of Unit 2's post-construction emissions based on "demand growth." This designation, if it could be established to the agency's satisfaction, also would have exempted DTE's modification from the necessity of a permit and, thus, allowed DTE to postpone some of the pollution-control installations that were planned as a future upgrade.[2] *See* 40 C.F.R. § 52.21(b)(41)(ii)(c). DTE began construction on Monroe Unit 2 without obtaining an NSR permit.

After investigation of DTE's projections, the EPA filed this enforcement action, challenging the company's routine-maintenance designation and its exclusion for "demand growth," and insisting that DTE should have secured a preconstruction permit and included pollution controls in the Unit 2 overhaul to remediate the projected emissions increases. The district court granted summary judgment to DTE, holding that the EPA's enforcement action was premature because the construction had not yet produced an actual increase in emissions. On appeal, we reversed and remanded, holding that the EPA was authorized to bring an enforcement action based on projected increases in emissions without first demonstrating that emissions actually had increased after the project. *DTE I*, 711 F.3d at 649.

On remand, the district court again entered summary judgment for DTE, this time focusing on language in our first opinion to the effect that "the regulations allow operators to undertake projects without having EPA second-guess their projections." *Id.* at 644. The district court apparently (and mistakenly) took this to mean that the EPA had to accept DTE's projections at face value, holding that:

> EPA is only entitled to conduct a *surface review* of a source operator's preconstruction projections to determine whether they comport with the letter of the law. Anything beyond this *cursory examination* would allow EPA to "second-

[1]As it turns out, the EPA does not consider a $65-million overhaul to be routine by definition.

[2]Those upgrades have since been completed. Since the Monroe Unit 2 overhaul was completed in 2010, DTE has installed the scrubbers and other pollution controls necessary to remediate toxic emissions at the facility, so that implementation is no longer at issue. Appellee's Br. at 13 n.4. But, if it is found to have violated the Act, DTE still could face monetary penalties and be required to mitigate excess emissions caused by the delay in installing pollution controls.

> guess" a source operator's calculations; an avenue which the Sixth Circuit explicitly foreclosed to regulators. [Emphasis added.]
>
> In this case, EPA claims that defendants improperly applied the demand growth exclusion when they "expected pollution from . . . Unit 2 to go up by thousands of tons each year after the overhaul," and then discounted this entire emissions increase by attributing it to additional consumer demand. In other words, EPA does not contend that defendants violated any of the agency's regulations when they computed the preconstruction emission projections from Unit 2. Rather, EPA takes defendants to task over *the extent* to which they relied upon the demand growth exclusion to justify their projections. This is exactly what the Sixth Circuit envisioned when it precluded EPA from second-guessing "the making of [preconstruction emission] projections." [Internal citations omitted.]

The problem with the district court's analysis is two-fold. First, the focus on so-called "second-guessing" is misplaced. That language from our earlier opinion is, technically speaking, *dictum*, because the holding of the opinion was, as noted above, that the EPA could bring a preconstruction enforcement action to challenge DTE's emissions projections. Second, in reviewing an operator's attribution of increased emissions to demand growth, the EPA definitely is not confined to a "surface review" or "cursory examination."

Indeed, two agency pronouncements, dating back to 1992, make clear that the EPA must engage in actual review. The first is in 57 Fed. Reg. 32,314, 32,327 (July 21, 1992), which is quoted in our first opinion: "[W]hether the [demand growth] exclusion applies 'is a *fact-dependent* determination that must be *resolved on a case-by-case basis*.'" *DTE I*, 711 F.3d at 646 (emphasis added). The second is found in 72 Fed. Reg. 72,607, 72,611 (Dec. 21, 2007) (emphasis added): NSR record-keeping requirements "establish[] an adequate paper trail to allow enforcement authorities to *evaluate* [an operator's] claims concerning what amount of an emissions increase is related to the project and *what amount is attributable to demand growth*."

But the EPA cannot *evaluate* a *fact-dependent* claim on a *case-by-case* basis unless the operator supplies supporting facts, which the record establishes was not done here. In other words, a valid projection must consist of more than the following list, which is, in effect, all that DTE provided to the EPA:

Increase in nitrous oxide emissions………………………..…....……………4,096 tons
Increase in sulfur dioxide emissions……………….................…………….3,701 tons

Total increase in emissions…………………………..........……………....7,797 tons

Less amount attributable to demand growth………………....…...………...7,797 tons

NSR projection for post-construction emissions…………....…………………..0 tons

The record before us is devoid of any support for this thoroughly superficial calculation.[3] DTE baldly asserted that it was excluding from its projections "'that portion of the unit's emissions following the project that an existing unit could have accommodated . . . and that are also unrelated to the particular project,' including increases due to demand and market conditions or fuel quality." Mar. 12, 2010 Notice Letter, Page ID 165 (quoting the Michigan equivalent of 40 C.F.R. § 52.21(b)(41)(ii)(c)). DTE then went on to claim that "emissions and operations fluctuate year-to-year due to market conditions," and "[a]t some point in the future, baseline levels may be exceeded again, but not as a result of this outage." *Id.* This letter provided no rationale for the company's claim that Unit 2 was capable of accommodating the increased emissions prior to the construction projects or that future growth in the demand for electricity was the sole cause of the projected increase in pollutants. Although DTE later sent two more letters to the EPA supposedly clarifying the method of calculating baseline emissions, these letters also failed to explain why DTE applied the demand-growth exclusion to its entire projected-emissions increase. In its motion for summary judgment below, DTE claimed that it attributed the increased emissions to future demand for power "[b]ased on the company's business and engineering judgment" (Page ID 6716), but gave no specific information to support that judgment.

In fact, not one of DTE's attempts to justify its application of the demand-growth exclusion was supported by documentation, without which the EPA could not meaningfully evaluate DTE's projections. There was, in truth, nothing to evaluate. Moreover, the results of a

[3]Clearly, DTE failed to comply with the regulation requiring it to "document . . . the amount of emissions excluded under paragraph (b)(41)(ii)(c) of this section and an explanation for why such amount was excluded." 40 C.F.R. § 52.21(r)(6)(i).

computer model that DTE ran, when it was rerun by the EPA, showed that DTE should actually have predicted a *decrease* in demand. (Page ID 372) Contrary to DTE's "business and engineering judgment," what did occur in the immediate post-construction period was a decline in consumer demand, not an increase. Appellee's Br. at 64.

DTE's failure to carry its burden to set out a factual basis for its demand-growth exclusion is just one problem with its projections. In order to exclude increased emissions as the product of increased demand under 40 C.F.R. § 52.21(b)(41)(ii), the company must establish (1) that the projected post-construction emissions could have been accommodated during the preconstruction period *and* (2) that the projected emissions are unrelated to the construction project.[4] As to the first requirement, DTE did not and could not establish that the increase in emissions could have been accommodated during the baseline period. Prior to the overhaul, DTE was running Unit 2 at full capacity—that is, Unit 2 was operating every hour that it could be operated. (Page ID 294) But Unit 2 was experiencing continual outages that kept it from running almost 20 percent of the time (Page ID 302), which is obviously why DTE shut it down for three months to accomplish the overhaul, aimed at increasing efficiency and reliability. For the same reason, DTE did not and could not establish that the increase in emissions was unrelated to the construction process. The planned increase in efficiency and reliability would allow the plant to operate for at least an additional 12 days each year (Page ID 306), which in turn would result in increased emissions unless the construction also had included pollution controls, as the issuance of a permit would have required.

In *DTE I*, we referenced the second sentence of 40 C.F.R. § 52.21(r)(6)(ii):

> If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i). *Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction.*

[4]Both requirements must be met. *See New York v. U.S. Envtl. Prot. Agency*, 413 F.3d 3, 33 (D.C. Cir. 2005) (citing 67 Fed. Reg. 80,186, 80,203 (Dec. 31, 2002)) ("[E]ven if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but it can be shown that the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the modification project, and cannot be subtracted from the projection of post-change actual emissions.").

711 F.3d at 650 (emphasis added). Judge Rogers's current dissent seems to take a broader view of this regulation than the text permits in repeatedly cautioning that permitting the EPA's enforcement action to go forward would create "a de facto prior approval system." (Rogers Opinion at 15, 17, 19) But this reading is patently too expansive, because the regulation does not say that the EPA has to accept projections at face value or that it is prohibited from questioning their legitimacy. Instead, and in context, the rule means that once the required information has been submitted to the EPA for review, the operator does not have to delay construction until it receives a decision on the necessity of a permit, but may commence construction prior to a "determination from the Administrator." Of course, if the operator actually begins construction without waiting for a "determination" from the EPA and it later turns out that a permit was required, a violation of NSR has occurred, and the operator risks penalties and injunctive relief requiring mitigation of illegal emissions, a possible shut down of the unit, or a retrofit with pollution controls to meet emissions standards. *See, e.g.*, *United States v. Cinergy Corp.*, 618 F. Supp. 2d 942, 971 (S.D. Ind. 2009), *rev'd on other grounds*, 623 F.3d 455 (7th Cir. 2010).

In short, DTE was not required by the regulations to secure the EPA's approval of the projections, or the project, before beginning construction, but in going forward without a permit, DTE proceeded at its own risk. The EPA is not prevented by law or by our prior opinion in *DTE I* from challenging DTE's preconstruction projections, such as they are. Viewing the facts in the light most favorable to the EPA, we conclude that there are genuine disputes of material fact that preclude summary judgment for DTE regarding DTE's compliance with NSR's statutory preconstruction requirements and with agency regulations implementing those provisions. Therefore, we REVERSE the district court's grant of summary judgment to DTE and REMAND this case for further proceedings consistent with this opinion.

In terms of the remand, it is important to note that the panel unanimously agrees—now that *DTE I* is the law of this case and of the circuit—that actual post-construction emissions have no bearing on the question of whether DTE's preconstruction projections complied with the regulations. (Batchelder Concurrence at 6, 7; Rogers Opinion at 20) *DTE I* foreclosed that question in holding that an operator who begins construction without making a projection in accordance with the regulations is subject to enforcement, no matter what post-construction data later shows. 711 F.3d at 649. The district court erred initially and again on remand when it ruled that post-construction data could be used to show that a construction project was not a "major modification." Apparently, it is necessary to reiterate that the applicability of NSR must be determined *before construction commences* and that liability can attach if an operator proceeds to construction without complying with the preconstruction requirements in the regulations. Post-construction emissions data cannot prevent the EPA from challenging DTE's failure to comply with NSR's preconstruction requirements.

CONCURRENCE IN THE JUDGMENT

ALICE M. BATCHELDER, Circuit Judge, concurring in the judgment only. When this appeal was here before, the majority vacated a grant of summary judgment and remanded for the USEPA to challenge DTE's pre-construction emission projections. I dissented because actual events had disproven USEPA's projected (hypothetical) emissions calculations (which were the entire basis for its claim), USEPA had not accused DTE of any noncompliance with any regulations, and the majority opinion was creating a de facto prior-approval or second-guessing scheme. *See United States v DTE Energy Co.* (*DTE I*), 711 F.3d 643, 652-54 (6th Cir. 2013) (Batchelder, J., dissenting). On remand, however, the district court again granted summary judgment to DTE, finding that USEPA had not raised a valid claim of regulatory non-compliance and reasserting that actual events had disproven USEPA's hypothetical emission projections. USEPA appealed again, relying on the prior decision by the *DTE I* majority.

Therefore, this time around we again face the question of whether USEPA may second guess DTE's preconstruction emission projections, using its own hypothetical projections, without regard to actual events. The dissent here would affirm this grant of summary judgment on the basis that USEPA has not raised a valid claim of regulatory non-compliance and mere second guessing is impermissible. That was my view during the prior *DTE I* appeal, as explained fully in that dissent, and I would very much like to agree. But, unlike the prior appeal, this appeal does not present an open issue and I cannot ignore the *DTE I* opinion or pretend that it means something other than what it says. Despite my continuing disagreement with it, *DTE I* is the law of the Sixth Circuit. Consequently, USEPA was entitled to rely on it and the district court was obliged to follow it. More importantly, we must follow it as well.

Simply put, the *DTE I* opinion clearly requires that we reverse the district court's grant of summary judgment to DTE and remand for reconsideration consistent with that prior opinion. Therefore, I concur in the judgment to REVERSE and REMAND, but I do not join any language or analysis in the lead opinion that could be read to expand the prior *DTE I* opinion.

I.

DTE Energy planned renovations at its Monroe Power Plant. In accordance with all applicable state and federal regulations, it conducted its own determination as to whether the renovations would constitute a "significant modification" that would require a PSD permit, and determined that it would not. Specifically, DTE relied on "demand growth" to predict that its post-project emissions would not increase from its baseline emissions levels and that there was no "reasonable possibility" that this renovation would be a significant modification.

But months later (after construction was well underway), USEPA sued DTE, claiming that—based on USEPA's expert's different hypothetical emission predictions—DTE should have gotten a PSD permit. DTE moved for summary judgment, arguing that a PSD permit was unnecessary based on either its pre-construction prediction or actual post-construction test results, which established that emissions did not increase (and actually decreased) after the renovation. Basically, USEPA wanted DTE to go back in time and re-do its predictions the same way USEPA's expert would have done them, so as to predict emissions increases and mandate a PSD permit, even though actual events had already proven USEPA's predictions were wrong.

The pertinent regulations say: "a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase . . . and a significant net emissions increase. . . . The project is not a major modification if it does not cause a significant emissions increase. . . . Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase." 40 C.F.R. § 52.21(a)(2)(iv).[1] I read this last sentence also to mean that,

[1] In their entirety:

(a) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, *a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase* (as defined in paragraph (b)(40) of this section), *and a significant net emissions increase* (as defined in paragraphs (b)(3) and (b)(23) of this section). *The project is not a major modification if it does not cause a significant emissions increase.* If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(b) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(c) through (f) of this section.

regardless of any pre-construction projections, a major modification *does not result* if the project *does not cause* an actual significant emissions increase or significant net emissions increase. But the *DTE I* panel majority did not read it this way, nor did USEPA. According to them, this regulation means that a renovation is a major modification (requiring a PSD permit) if either a USEPA-approved calculation predicts an emissions increase or emissions actually increase. And, despite the fact that the rules delegate calculation of the prediction to the operator (here DTE), and contain no requirement that the operator obtain USEPA review or approval, USEPA deems both the operator's prediction and reality meaningless if USEPA disagrees.

Leading in to *DTE I*, the district court had rejected USEPA's view and granted summary judgment to DTE in a thorough, well-written, and (I thought) correct opinion, explaining that DTE had followed the regulations and predicted no "significant modification," thus excusing it from the permit requirements. Moreover, actual events had proven DTE's prediction correct (and USEPA's incorrect). But, on appeal, the *DTE I* majority reversed, opining that: "[a] preconstruction projection is subject to an enforcement action by EPA to ensure that the projection [wa]s made pursuant to the requirements of the regulations." *DTE I*, 711 F.3d at 652.

I dissented on three bases. First, the subsequent actual emissions data, which showed an actual emissions *decrease*, "render[ed] moot the case or controversy about *pre*-construction emissions projections—there can be no permitting or reporting violation because there was, conclusively, no major modification." *Id.* (Batchelder, J., dissenting). Next, I explained that, regardless of any purported disclaimer that this was not a prior approval scheme, the reality is that "if the USEPA can challenge the operator's scientific preconstruction emissions projections in court—to obtain a preliminary injunction pending a court decision as to whether the operator or USEPA has calculated the projections correctly—that is the exact same thing as requiring prior approval." *Id.* at 653 (Batchelder, J., dissenting) (footnote omitted). Finally, I explained (twice) that USEPA was *not* claiming that DTE had failed to follow the regulations:

> The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition in paragraph (b)(3) of this section. *Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.*

40 C.F.R. § 52.21(a)(2)(iv) (emphasis added).

> To be sure, neither of these issues is in question here: there is no contention that DTE failed to prepare a projection (it did) or that DTE misread the rules in applying the governing regulation (it did not). Instead, USEPA relies on its expert's opinion to second-guess DTE's projections. *See* Appellant Br. at 25 ("EPA can use its projections to demonstrate that the operator should have projected a PSD-triggering emissions increase."); 24 ("The agency can use its own emissions projections to demonstrate that a proper pre-construction analysis would have shown an emissions increase."). USEPA's disagreement is entirely technical and scientific; the dispute is not about the regulation.

Id. at 652 n.1 (Batchelder, J., dissenting).

> It bears repeating that USEPA does not contend that DTE failed to make a projection or failed to follow the regulations; rather, USEPA relies on its expert's opinion to second-guess DTE's technical/scientific projections. *See* n.1, *supra.* If the issue here had been one of the foregoing (i.e., if USEPA had wanted to challenge an operator's failure to make a projection or failure to follow the governing regulation—a challenge that would not require USEPA to rely on an expert's scientific opinion), that would present different considerations and perhaps result in a different outcome. Because neither of those issues is before us, it is neither necessary nor appropriate to address them here.

Id. at 652 n.2 (Batchelder, J., dissenting). If the *DTE I* holding had been that USEPA was limited to challenging only whether DTE had failed to follow the regulation, the *DTE I* majority would have had no basis for reversal, inasmuch as USEPA had not raised any such challenge. Instead, *DTE I*'s inescapable actual holding was that USEPA may use its own expert's pre-construction predictions to force DTE to get a PSD construction permit (or to punish DTE for failing to get a PSD permit), even if USEPA's disagreement is based on debatable scientific or technical reasons and even if actual events have proven USEPA's expert's prediction wrong.

On remand, however, the district court tried to limit the *DTE I* holding rather than just doing as instructed, and once again granted summary judgment to DTE, saying:

> In this case, EPA claims that defendants improperly applied the demand growth exclusion when they expected pollution from Unit 2 to go up by thousands of tons each year after the overhaul and then discounted this entire emissions increase by attributing it to additional consumer demand. In other words, EPA does not contend that defendants violated any of the agency's regulations when they computed the preconstruction emission projections from Unit 2. Rather, EPA takes defendants to task over *the extent* to which they relied upon the demand growth exclusion to justify their projections. This is exactly what the

> Sixth Circuit envisioned when it precluded EPA from second-guessing the making of preconstruction emission projections. Moreover, EPA does not point to any regulation requiring source operators to demonstrate the propriety of their demand growth exclusion calculations. And without adequate proof that defendants violated the regulations governing preconstruction emission projections, the instant action cannot withstand summary judgment.
>
> Even assuming that EPA's reviewing authority is as broad as the agency claims, the Court is bewildered by the prospect of what, if anything, the agency stands to gain by pursuing this litigation. Insofar as the government asserts that defendants misapplied the demand growth exclusion, this contention is belied by the fact that defendants have demonstrated, and the government concedes, that the actual post-project emissions from Unit 2 never increased. Therefore, since its own preconstruction emission projections are now verifiably inaccurate, the government is unable to show that the renovations to Unit 2 constituted a major modification.

R. 196 at 3-4; PgID 7515-16 (quotation marks, editorial marks, and citations omitted).

This analysis ignores two major holdings from *DTE I*. First, DTE had already established in *DTE I* that the actual post-project emissions had decreased, so even knowing that USEPA's pre-construction projections were "verifiably inaccurate," *DTE I* still remanded for a ruling on the *pre*-construction projections, rendering the actual emissions legally irrelevant. Second, we were also fully aware in *DTE I* that USEPA was not claiming that DTE had overlooked, misapplied, or violated any regulations; USEPA's only claim was that DTE had scientifically miscalculated the predicted emissions. If the question had been whether or not USEPA could challenge DTE's failure to comply with the regulations, then *DTE I* would have affirmed the summary judgment because USEPA had raised no such claim. And I would have had no need to dissent.[2] Rather, the *DTE I* majority remanded for a ruling on USEPA's claim that DTE had technically or scientifically miscalculated the hypothetical pre-construction emissions.

[2] As I said in that dissent: "It bears repeating that USEPA does not contend that DTE failed to make a projection or failed to follow the regulations. . . . [I]f USEPA had wanted to challenge an operator's failure to make a projection or failure to follow the governing regulation. . . , that would present different considerations and perhaps result in a different outcome." *DTE I*, 711 F.3d at 652 n.2 (Batchelder, J., dissenting).

II.

Now, USEPA appeals the grant of summary judgment and argues that the district court did not follow the *DTE I* majority's remand instructions.

A.

On remand, USEPA re-framed its claims against DTE as noncompliance with particular regulations in an admitted effort to satisfy the *DTE I* majority's purported limiting language. That is, USEPA now argues that DTE violated the regulations "in two critical ways." Apt. Br. at 51. First, USEPA claims that DTE failed to base its predictions on "all relevant information," required by 40 C.F.R. § 52.21(b)(41)(ii)(a), and ignored its own modeling when claiming that any increase was due to demand increases, in violation of 40 C.F.R. § 52.21(b)(41)(ii)(a). Second, USEPA claims that, in applying the demand growth exclusion, DTE excluded emissions that USEPA believed were related to the project, contrary to § 52.21(b)(41)(ii)(c).

According to the *DTE I* opinion, this is a legitimate challenge. In fact, this is a far more legitimate challenge than that which the majority opinion condoned in the *DTE I* appeal. Given the *DTE I* holding, the district court erred by rejecting this challenge.

B.

USEPA also argues that "[w]here a source should have expected a project to increase emissions, the work is a major modification and must meet the modification requirements" regardless of "post-project data." Apt. Br. at 54. USEPA relies on the fact that the *DTE I* panel "knew that post-project data showed an emissions decrease, and yet … remanded for further proceedings" anyway; if post-project data were determinative, "there would have been no reason for that remand." Apt. Rep. Br. at 9-10. This reasoning actually applies throughout.

III.

Based on the foregoing, I conclude that, because we are bound by the *DTE I* opinion, we must reverse the grant of summary judgment to DTE and remand for reconsideration consistent with that prior opinion. Therefore, I concur in the judgment to REVERSE and REMAND. I do not join any language or analysis that expands or alters the prior opinion.

DISSENT

ROGERS, Circuit Judge, dissenting. The Clean Air Act requires an operator of a major source of air pollution to obtain a permit before beginning construction on a project that the operator predicts will significantly increase pollution at the operator's source. In 2010, EPA brought an enforcement action against DTE Energy Company and Detroit Edison Company, alleging that the defendants had violated the Clean Air Act by failing to obtain permits before beginning construction on projects at their power plant in Monroe, Michigan. DTE contended that EPA's enforcement action was premature because DTE's projects had not yet caused pollution to increase, and the district court agreed. On appeal, this court reversed the district court's grant of summary judgment to DTE, holding that EPA could bring an enforcement action to ensure that an operator performed a pre-construction projection about whether its proposed project would cause pollution to increase, but that full review of the validity of the projection at the pre-construction stage was not consistent with the statute and regulatory scheme. On remand, the district court granted DTE's renewed motion for summary judgment, reasoning that DTE met the basic requirements, and also because in any event post-construction emissions had not increased. EPA appeals.

Because the undisputed facts establish that DTE complied with the basic requirements of the regulations for making projections, the district court properly granted summary judgment to DTE.

I.

A.

This court's prior opinion explains the regulatory framework that governs this case:

> The 1977 Amendments to the Clean Air Act created a program titled New Source Review. New Source Review forbids the construction of new sources of air pollution without a permit. 42 U.S.C. § 7475. In order to achieve the act's goals of "a proper balance between environmental controls and economic growth," sources already in existence when the program was implemented do not have to

> obtain a permit unless and until they are modified. *New York v. EPA*, 413 F.3d 3, 13 (D.C. Cir. 2005) (quoting 123 Cong. Rec. 27,076 (1977) (statement of Rep. Waxman)). Congress defined a modification as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4). EPA requires owners or operators of [major stationary] sources to obtain permits if they plan a "major modification." [40 C.F.R. § 52.21(a)(2)(iii).] A [major stationary] source is anything that has the potential to emit large quantities of a regulated pollutant. [40 C.F.R § 52.21(b)(1)(i)(a).] A major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated [New Source Review] pollutant . . . and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 52.21(b)(2)(i).

United States v. DTE Energy Co., 711 F.3d 643, 644–45 (2013) (footnotes omitted).

The 2002 New Source Review rules,[1] as adopted by EPA in 2002, provide that for projects that only involve existing emissions units, a "significant emission increase of a regulated [New Source Review] pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . for each existing emissions unit, equals or exceeds the significant amount for that pollutant." 40 C.F.R. § 52.21(a)(2)(iv)(c). To determine whether a project would cause a significant emissions increase, and thus require a permit, an operator must therefore follow three basic steps.

First, the operator must determine the "baseline actual emissions."

Second, the operator must determine the "projected actual emissions." The "projected actual emissions" can be calculated by determining "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated [New Source Review] pollutant in any one of the 5 years (12–month period) following the date the unit resumes regular operation after the project." 40 C.F.R. § 52.21(b)(41)(i). To calculate this amount, the operator must "consider all relevant information, including but not limited to . . . the company's own representations, the company's expected business activity . . . [and] the company's filings with

[1] New Source Review actually consists of two programs: "New Source Review for areas classified as 'nonattainment' for certain pollutants and Prevention of Significant Deterioration for areas classified as 'attainment.' Monroe, Michigan actually falls into both categories depending on the pollutant. The two programs are generally parallel and their differences do not affect this case." *DTE Energy*, 711 F.3d at 644 n.1.

the State or Federal regulatory authorities." 40 C.F.R. § 52.21(b)(41)(ii)(a). Further, the operator "[s]hall exclude" from the projected actual emissions "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(c). "Since the most common independent factor is growth in demand for electricity, the exclusion [of this portion of the unit's emissions] is called the 'demand growth exclusion.'" *DTE Energy Co.*, 711 F.3d at 646.

Third, the operator must subtract the baseline actual emissions from the projected actual emissions to determine if the difference between these numbers is "significant." 40 C.F.R. § 52.21(a)(2)(iv)(c). A table in the regulations defines the numeric thresholds that are considered "significant" for each regulated pollutant. 40 C.F.R. § 52.21(b)(23)(i). If the table defines the difference in the projected actual emissions and the baseline actual emissions to be significant, then the operator must obtain a permit before beginning construction on the project. 40 C.F.R. § 52.21(a)(2)(iii). "[A] permit would require the facility to use 'best available control technology' for each regulated pollutant. For grandfathered sources, installing this technology generally leads to a drastic decrease in emissions, even when compared to the preconstruction baseline, at great expense for the operator." *DTE Energy Co.*, 711 F.3d at 645 (citing 42 U.S.C. § 7475(a)(4)).

B.

Detroit Edison Company, a wholly-owned subsidiary of DTE Energy Company, owns and operates the Monroe Power Plant in Monroe, Michigan. In March 2010, DTE began construction projects at Monroe Unit #2, a coal-fired generating unit at the Monroe Power Plant. The projects included the replacement of several components of the unit's boiler tube, including the unit's economizer, pendant reheater, and a portion of the waterwall.

On March 12, 2010, before beginning these projects, DTE submitted calculations about the projects' expected impact on emissions to its reviewing authority, the Michigan Department of Environmental Quality. To make these calculations, DTE used projections that it had previously provided to the Michigan Public Service Commission. DTE created these projections using a "complex 'production cost model' called PROMOD." PROMOD relies on "a number of company-defined inputs"—such as projected market prices for coal and natural gas and expected outage rates—to predict how much Monroe Unit #2 would be used in the future. DTE projected that in the five years after the projects, Monroe Unit #2 would have its maximum emissions of nitrogen oxide and sulfur dioxide in 2013, with emissions increases of 4,096 tons of nitrogen oxide and 3,701 tons of sulfur dioxide at this time. Both of these amounts are more than 40 tons per year increases of either sulfur dioxide or nitrogen oxide, increases which the regulations deem to be significant. 40 C.F.R. § 52.21(b)(23)(i).

However, DTE concluded that the projects would not result in an emissions increase. To reach this conclusion, DTE excluded all of its projected emissions increases from its "projected actual emissions" under the demand growth exclusion. DTE Vice President of Environmental Management and Resources Skiles W. Boyd stated that DTE determined that its projected increase in emissions was "attributable to demand growth" based on its "prediction that there would be substantial demand for electricity generated at DTE's coal-fired power plants in 2013 due to the predicted price of coal versus the price of natural gas and other factors." Boyd also stated that DTE concluded that it could have accommodated these emissions during the baseline period because Monroe Unit #2 "had greater availability during the baseline period than the highest expected utilization of the unit after the project."

On May 28, 2010, EPA sent DTE a letter asserting that its projects constituted a "major modification" and ordering DTE to produce "[a]ny additional information" that supported its contention that the projects did not require a permit. DTE responded on June 1, 2010, stating that its projected increases were "completely unrelated to the project." DTE explained that at the time that it made its projections "a primary driver for a projected increase in generation (and commensurate projected increase in emissions) from the Monroe Power Plant was an expected increase in power demand accompanied by an increase in energy cost." DTE stated that this "increase in power demand" led to "other factors" that influenced emissions. These factors included the fact that Monroe Unit #2 had no periodic outage scheduled in 2013, the year in which DTE projected that the unit would have its maximum emissions, while it had outages planned in 2010, 2012 and 2014. DTE explained that Monroe Unit #2 had no planned outage in 2013 in part because an outage was planned for Monroe Unit #1 in this year and "Monroe Unit 2 must help make up the difference in electricity demand." DTE also explained that it had determined that Monroe Unit #2 "could have generated" the projected increases in emission during the baseline period "had the market required the electricity during our baseline period."

The projects concluded on June 20, 2010. Since the projects were completed, emissions at Monroe Unit #2 have not exceeded pre-project emissions on an annualized basis, and actual emissions were less than baseline emissions in 2011 and 2012.

In June 2010, EPA issued DTE a notice of violation stating that the projects "resulted in a significant net emissions increase" and therefore constituted a "major modification" for which DTE was required to obtain a permit. In August 2010, the United States, acting at the request of EPA, filed a complaint against DTE in federal district court alleging that DTE had violated the Clean Air Act by proceeding to construction on a major modification without obtaining New Source Review permits. Soon after this, the district court ordered DTE not to use Monroe Unit #2 "to any extent that is greater than it was utilized" prior to the completion of the projects and granted Sierra Club's motion to intervene as plaintiffs. The district court subsequently granted DTE's motion for summary judgment, concluding that a determination of whether the projects at issue constituted a major modification was premature because EPA "may pursue [New Source Review] enforcement if and when post-construction monitoring shows a need to do so." The district court also rejected EPA's challenges to the procedural sufficiency of DTE's notice letter to the Michigan Department of Environmental Quality, holding that DTE complied with the Michigan state-law equivalent to the New Source Review reporting requirements.

On appeal, this court reversed, holding that while the "district court's premises are largely correct, they do not support its sweeping conclusion" that "preconstruction New Source Review enforcement is flatly unavailable if reporting requirements are met." 711 F.3d at 649.[2] This court explained that the current New Source Review regulations "take a middle road" between requiring "operators to defend every projection to the agency's satisfaction" and barring

[2]EPA did not appeal the district court's decision that DTE's notice complied with the reporting requirements. *DTE Energy*, 711 F.3d at 649.

EPA from "challenging preconstruction projections that fail to follow regulations" by "trusting operators to make projections but giving them specific instructions to follow." *Id.* This court explained:

> The primary purpose of the projection is to determine the permitting, monitoring, and reporting requirements, so as to facilitate the agency's ability to ensure that emissions do not increase. If there is no projection, or the projection is made in contravention of the regulations guiding how the projection is to be made, then the system is not working. But if the agency can second-guess the making of the projections, then a project-and-report scheme would be transformed into a prior approval scheme. Contrary to the apparent arguments of the parties, neither of these is the case. Instead, at a basic level the operator has to make a projection in compliance with how the projections are to be made. But this does not mean that the agency gets in effect to require prior approval of the projections.

Id.

This court reasoned that the Clean Air Act provides EPA with the ability to "take such measures . . . [that are] necessary to prevent the construction or modification of a major emitting facility which does not conform to the requirements of [the Clean Air Act]." *Id.* at 650 (citing 42 U.S.C. § 7477). Because these requirements "include making projections," in accordance with the rules set forth in the regulations, this court concluded that "EPA's enforcement powers must also extend to ensuring that operators follow the requirements in making those projections." *Id.* EPA could, for instance, bring an enforcement action against an operator who commences construction on a project without making any preconstruction projection. *Id.* EPA could also prevent construction if an operator "uses an improper baseline period or uses the wrong number to determine whether a projected emissions increase is significant." *Id.* This court therefore held that a "preconstruction projection is subject to an enforcement action by EPA to ensure that the projection is made pursuant to the requirements of the regulations" and remanded the case to the district court. *Id.* at 652.

On remand, DTE again moved for summary judgment, arguing that the undisputed facts established that it had complied with the regulations' objective requirements for making preconstruction projections. The district court granted DTE's motion, concluding that this court's decision allows EPA to conduct only "a surface review of a source operator's preconstruction projection to determine whether they comport with the letter of law." *United*

States v. DTE Energy Co., No. 10-cv-13101, 2014 WL 12601008, at *1 (E.D. Mich. Mar. 3, 2014). The district court explained that anything "beyond this cursory examination would allow the EPA" to engage in impermissible "second-guessing" of an operator's calculations. *Id.* The district court determined that EPA had not contended that DTE violated any of the agency's regulations when DTE made its projection but rather impermissibly challenged "*the extent* to which [DTE] relied upon the demand growth exclusion." *Id.* Accordingly, the district court held that EPA's enforcement action failed as a matter of law because there was not "adequate proof that [DTE] violated the regulations governing preconstruction emission projections." *Id.*

Alternatively, the district court held that even if EPA had unfettered authority to challenge the methodology and factual assumptions that DTE used to predict post-project emissions, the district court was "bewildered" by what EPA stood to gain by pursuing the litigation because "the actual post-project emissions from [Monroe] Unit 2 never increased." *Id.*, at *2. The district court explained that the actual post-project emissions established that EPA's "own preconstruction emission projections" were inaccurate and that EPA therefore could not show that DTE's projects constituted a major modification. *Id.*

II.

This court reviews the district court's partial grant of summary judgment to DTE *de novo*. *Therma-Scan, Inc. v. Thermoscan, Inc.*, 295 F.3d 623, 629 (6th Cir. 2002).[3] Summary judgment was proper because the undisputed facts establish that DTE complied with the basic requirements for making projections. *DTE Energy*, 711 F.3d at 649–50. EPA contends that it

[3]Even though some of EPA and Sierra Club's claims against DTE have not been dismissed, this court has jurisdiction to review the district court's partial grant of summary judgment to DTE based on the district court's Rule 54(b) certification. A "district court may certify a partial grant of summary judgment for immediate appeal" under Federal Rule of Civil Procedure 54(b) "if the court expressly determines that there is no just reason for delay." *Planned Parenthood Southwest Ohio Region v. DeWine*, 696 F.3d 490, 500 (6th Cir. 2012). In certifying such a judgment, the district court must (1) "expressly direct the entry of final judgment as to one or more but fewer than all claims or parties in a case" and (2) "expressly determine that there is no just reason to delay appellate review." *Id.* (quoting *Gen. Acquisition, Inc. v. GenCorp., Inc.*, 23 F.3d 1022, 1026 (6th Cir. 1994)). The district court properly certified its 2014 grant of partial summary judgment to DTE for immediate appeal under Rule 54(b) because the district court entered final judgment on EPA's and Sierra Club's claims relating to DTE's 2010 construction projects at Monroe Unit #2. The remaining claims by EPA and Sierra Club involved DTE's completion of distinct, unrelated construction projects. Further, the district court did not abuse its discretion in concluding that there was no just reason to delay immediate appellate review of its grant of partial summary judgment.

alleged that DTE failed to comply with the express regulatory requirements for making projections by: (1) failing to consider all relevant information when making its projection; (2) improperly applying the demand growth exclusion; and (3) failing to explain its use of the demand growth exclusion. In order to be excluded under the demand growth exclusion, an emissions increase must be unrelated to the operator's proposed project. 40 C.F.R. § 52.21(b)(41)(ii)(c). An emissions increase is not related to the project if the increase is caused by growth in demand for electricity after the project is complete. *DTE Energy Co.*, 711 F.3d at 646. However, an emissions increase is related to the proposed project if the increase is caused by improved reliability, lower operating costs, or other improved operational characteristics of the unit after the project is complete. 61 Fed. Reg. 38,250, 38,268 (July 23, 1996). EPA claims that DTE excluded all of its predicted emissions under the demand growth exclusion even though DTE's computer modeling and project documents predicted that the operational improvements at Monroe Unit #2, rather than an increased demand for electricity, would cause these increased emissions. EPA therefore contends that DTE violated the express requirements of the regulations by excluding emissions that were related to DTE's proposed projects.

Contrary to EPA's contention, there is no genuine issue of material fact about whether DTE's projection complied with the basic requirements for making projections. EPA does not contend that DTE violated the regulations by failing to make any projection. Nor does EPA contend that DTE violated the basic requirements of the regulations. Rather, EPA questions: (1) DTE's interpretation of the relevant information; (2) the methodology that DTE used to reach its conclusion that its predicted emissions increase could be excluded under the demand growth exclusion; and (3) the adequacy of DTE's explanation of why it reached this conclusion.

First, there is not a genuine issue of material fact about whether DTE violated the basic requirements of the regulations by ignoring relevant information. The regulations governing projections require an operator to "consider all relevant information" in determining its projected actual emissions, including but not limited to "the company's expected business activity" and "the company's filings with State or Federal regulatory authorities." 40 C.F.R. § 52.21(b)(41)(ii)(a). EPA claims that DTE ignored the relevant information because DTE created a "best estimate" computer model that reflected DTE's expected business activity and filings with a state regulatory authority but that DTE then ignored this model when it claimed that its predicted emissions increase was unrelated to its projects. EPA Br. at 39. To support this contention, EPA argues that running DTE's "best estimate" computer modeling with and without the changes caused by the projects showed that DTE's predicted emission increase would be caused by increased availability of Monroe Unit #2 after the projects were complete. *Id.* at 36–37. EPA claims that DTE ignored this modeling when claiming that its predicted increase was unrelated to the projects. EPA contends that DTE instead relied on its principal environmental engineer's "unsubstantiated" belief that a boiler tube component replacement project—like the economizer replacement at issue here—could not cause an emissions increase. *Id.* at 39.

This argument does not show that DTE violated the basic requirements of the regulations by failing to consider all relevant information. This claim is premised upon EPA's attempt to challenge the validity of DTE's conclusion that its predicted emissions increase was unrelated to its proposed projects. EPA does not contend that DTE failed to consider particular sources of relevant information when it created its computer modeling because EPA agrees that DTE's projection was based on a "'sophisticated' computer model" that considered "'exhaustive' inputs." United States Br. at 13. Accordingly, EPA's complaint at bottom is not that DTE failed to consider all the relevant information. Rather, EPA contends that DTE must have misinterpreted the relevant information in order to conclude that its projected increase was unrelated to the projects. The regulations for making projections do not state that an operator must interpret relevant information in a certain way or arrive at certain conclusions after examining relevant information. Error in interpretation of information is not, in short, failure to consider information.

Similarly without merit is Sierra Club's contention that DTE violated the regulations by failing to consider a projection that DTE submitted to the Michigan Public Service Commission. Sierra Club Br. at 13–14. This projection, which was based upon the same PROMOD modeling that DTE used to make its preconstruction projection, projected lower annual system energy demand in each of the five years after the projects than in each of the five years before the projects. Sierra Club contends that DTE's projection that the demand would decline in its overall system is inconsistent with its projection that demand for Monroe Unit #2 would increase. Sierra Club Br. at 13–14. It is true that DTE's statement to EPA that the projected emissions increase at Monroe Unit #2 was due in part to an "an increase in demand for the system as a whole" appears to be inconsistent with DTE's projection to the Michigan Public Service Commission that its annual system energy demand would decrease after the projects were complete. However, as stated above, DTE concluded that its projected increase in emissions at Monroe Unit #2 was due in part to the fact that this unit would need to generate more energy in 2013 to help make up for an extended outage of Monroe Unit #1 in 2013. DTE therefore could have projected that demand for energy at Monroe Unit #2 would increase in 2013, even if the demand for energy in DTE's overall system decreased. The Sierra Club therefore does not show that DTE failed to consider all relevant information in order to conclude that its projected emissions increase was unrelated to the projects.

Second, there is not a genuine issue of material fact about whether DTE followed the basic methodological requirements of the regulations when DTE excluded its predicted emissions increase under the demand growth exclusion. The demand growth exclusion provides that in making a preconstruction projection, an operator shall exclude the portion of the unit's emissions following the project that "could have [been] accommodated" during the baseline period and that are "unrelated to the particular project, including any increased utilization due to product demand growth." 40 C.F.R. § 52.21(b)(41)(ii)(c). EPA contends that DTE improperly applied the demand growth exclusion because DTE excluded all of its predicted emissions increase under this exclusion even though its computer modeling and project documents demonstrated that much of its predicted emissions increase was related to the projects. EPA Br. at 36–37; EPA Reply Br. at 24. To support this assertion, EPA relies on its expert witness Philip Hayet's opinion that an analysis of DTE's computer modeling showed that Monroe Unit #2 would break down less after the projects were complete and would be able to generate more electricity and emissions. To reach this conclusion, Hayet used a "standard industry methodology" that ran DTE's model with and without the effects of the projects while keeping all other inputs the same. EPA also contends that, like DTE's computer modeling, DTE's project documents predicted that the Monroe Unit #2 would generate more electricity and pollution after the projects were complete because Monroe Unit #2 would break down less frequently. EPA Br. at 37.

However, EPA does not point to any rule in the regulations that establishes that DTE is required to perform Hayet's "standard industry methodology" in order to evaluate whether the predicted emissions could be excluded under the demand growth exclusion. Similarly, EPA does not point to any language in the regulations that establishes the weight that DTE is required to place on its project documents when determining whether predicted emissions can be excluded under the demand growth exclusion. EPA also does not point to language in the regulations that sets forth rules for how DTE should interpret its project documents.

The issue of whether the demand growth exclusion applies to an operator's predicted emissions increase "is a fact-dependent determination that must be resolved on a case-by-case basis." *DTE Energy*, 711 F.3d at 646 (quoting 57 Fed. Reg. 32,314, 32,327 (July 21, 1992)). Accordingly, requiring DTE to establish that its application of the exclusion was more reasonable than EPA's application of the exclusion would turn New Source Review into a *de facto* prior approval scheme by requiring a district court to hold a trial to resolve this issue before the operator could proceed to construction. EPA therefore cannot show that DTE violated the regulations for applying the demand growth exclusion by contending that EPA would have applied this exclusion differently if EPA had been tasked with making the projection.

EPA also relies on EPA guidance about what it means for an emission to be "unrelated" to a project to support its argument that DTE violated the regulations by excluding a portion of DTE's projected emissions increase, which the regulations provide cannot be excluded. This reliance is misplaced. EPA repeatedly cites its statement that an increase in emissions must be "completely unrelated" to an operator's proposed project in order to be excluded under the demand growth exclusion. EPA Br. at 9, 28, 34–35. This statement does not provide operators with instructions about how to determine whether predicted emissions were completely unrelated to proposed projects. This statement also does not codify the methodology that EPA used to determine that DTE's predicted emissions increase was related to its proposed projects. Accordingly, this statement does not establish that DTE violated the regulations for applying the demand growth exclusion.

EPA's reliance on a statement in a preamble to proposed rulemaking from 1996 is similarly misplaced. In this preamble, EPA stated that when "the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (July 23, 1996). EPA seizes upon this language to contend that DTE's prediction that the projects would increase availability and reliability at Monroe Unit #2 is sufficient to establish that DTE's projected emissions increase was related to the projects. EPA Br. at 28, 37. This contention fails because EPA ignores its statement in the preamble that it "declined to create a presumption that every emissions increase that follows a change in efficiency . . . is inextricably linked to the efficiency change." 61 Fed. Reg. at 38,268.

Other EPA guidance also establishes that an emissions increase that follows a change in a unit's reliability or availability is not necessarily related to that change. In particular, in analyzing the 1992 New Source Review rules, EPA observed that "there is no specific test available for determining whether an emissions increase indeed results from an independent factor such as demand growth, versus factors relating to the change at the unit." 63 Fed. Reg. 39,857, 39,861 (July 24, 1998). The EPA therefore suggested not allowing operators to exclude "predicted capacity utilization increases due to demand growth from their predictions of future emissions." *Id.* However, EPA did not remove the demand growth exclusion. Instead, EPA kept the exclusion, recognizing that New Source Review record-keeping requirements establish "an adequate paper trail to allow enforcement authorities to evaluate [an operator's] claims concerning what amount of an emissions increase is related to the project and what amount is attributable to demand growth." 72 Fed. Reg. 72,607, 72,611 (Dec. 21, 2007).

Third, EPA's assertion that DTE violated the regulations by failing to properly explain why it excluded all of its projected emissions increases lacks merit. The regulations require an operator to "document and maintain a record of . . . the amount of emissions excluded" under the demand growth exclusion and "an explanation for why such amount was excluded" before beginning construction on a project. 40 C.F.R. § 52.21(r)(6)(i)(c). EPA contends that DTE violated this requirement by sending state regulators a letter that asserted that the demand growth exclusion applied to its predicted emissions increase without providing any factual support for this assertion. EPA Br. at 32–35.[4]

As the district court noted, although DTE's explanation of its use of the demand growth exclusion is not very detailed and "the accompanying table shows the results of the calculations without their back-up data, [EPA] does not point to any provision in [Michigan's equivalent to the New Source Review] rules requiring specificity beyond that which was provided." EPA also does not point to any regulation that describes the amount of detail that an operator is required to include in order to comply with the requirement to maintain an explanation of the operator's use of the demand growth exclusion. Allowing an enforcement action in this context would effectively turn the New Source Review into a *de facto* prior approval system.

EPA and Sierra Club's other arguments in support of allowing this enforcement action to continue are also unavailing. EPA contends that requiring it to defer to an operator's judgment about the projection itself and about whether the demand growth exclusion applies to the operator's predicted emissions increase would result in a voluntary New Source Review program for existing sources. To support this assertion, EPA claims that it will not be able to effectively evaluate potential increases in air pollution if the reasonableness of the projection and the applicability of the demand growth exclusion are "left to the source's unfettered discretion." EPA Reply Br. at 28. However, forbidding EPA from challenging an operator's projection on the basis that EPA would have used different methodology to create the projection or would have reached a different conclusion about whether the demand growth exclusion applied to the operator's predicted emissions increase is not equivalent to leaving the applicability of the demand growth exclusion and the making of the projection to the sole discretion of the operator. Rather, EPA can still challenge operators who fail to follow the basic requirements of the regulations by failing to make and record their preconstruction projections, by providing no

[4]EPA contends that it did not allege that DTE had failed to comply with § 52.21(r)(6)(i)(c). EPA Reply Br. at 24 n.2. However, EPA claimed that DTE did not provide an "explanation" to support its exclusion of its projected emissions as required under § 52.21(r)(6)(i)(c) and claimed that DTE had not adequately supported its claim that the projected emissions increase could be excluded under the demand growth exception. EPA Br. at 32–35. Accordingly, EPA's allegation that DTE failed to adequately support its use of the demand growth exclusion appears to be based upon EPA's contention that DTE violated the requirement to provide an adequate explanation of its use of the demand growth exclusion under § 52.21(r)(6)(i)(c).

explanation for their applications of the demand growth exception, or by excluding predicted emissions that the operators conclude are related to their projects.

EPA further contends that requiring it to defer to an operator's judgment about whether a predicted emissions increase can be excluded under the demand growth exclusion would require EPA to also defer to the operator's determination about whether an actual increase in emissions could be excluded under the demand growth exclusion. EPA Reply Br. at 28–29. This assertion is unavailing. This court's prior opinion did not foreclose EPA from challenging the reasonableness of an operator's determination that an actual post-construction increase in emissions was unrelated to the project. To the contrary, this court explained that "[a]n operator takes a major risk if it underestimates projected emissions" because the operator will face large penalties "[i]f post-construction emission are higher than preconstruction emissions, and the increase does not fall under the demand growth exclusion." *DTE Energy*, 711 F.3d at 651. Accordingly, this court's prior opinion indicates that EPA does not need to defer to an operator's determination about whether an actual increase in emissions after construction was related to the project.

EPA also contends that *Alaska Dep't of Envtl. Conservation v. EPA* establishes that EPA can also challenge the reasonableness of DTE's preconstruction projection. EPA Reply Br. at 21–23. This contention fails. In *Alaska Dep't*, the Supreme Court held that EPA can evaluate whether a state's imposition of pollution controls in an operator's permit was "reasonably moored to the [Clean Air] Act's provisions." 540 U.S. 451, 485, 488–90 (2004). Unlike DTE's projection, which was made before DTE decided whether it needed to obtain a permit, the pollution controls in *Alaska Dep't* were created after the operator had independently concluded that it had to obtain a permit before beginning construction. *Id.* at 474–75. EPA's ability in *Alaska Dep't* to challenge the reasonableness of pollution controls included in a permit did not turn New Source Review into a *de facto* prior approval scheme by allowing EPA to "in effect . . . require prior approval of [an operator's] projections." *DTE Energy*, 711 F.3d at 649. *Alaska Dep't* is therefore inapposite.

EPA and Sierra Club also contend that EPA's enforcement action must be allowed to continue because a ruling in DTE's favor would harm public health and the economy. To support this assertion, EPA and Sierra Club explain that DTE's conclusion that it was not required to obtain a permit before beginning construction allowed it to delay installing updated pollution controls in Monroe Unit #2 for four years. Sierra Club Reply Br. at 21–21; EPA Br. at 53. EPA and Sierra Club contend that the increased pollution resulting from this delay resulted in "approximately 90 premature deaths and total social costs of $500 million" each year that the pollution controls were delayed. Sierra Club Reply Br. at 21; EPA Br. at 53–54. As this court previously explained, New Source Review is not designed to "force every source to eventually adopt modern emissions control technology." *DTE Energy*, 711 F.3d at 650. Accordingly, the fact that DTE was able to delay imposing updated pollution controls by "keep[ing] its post-construction emissions down in order to avoid the significant increases that would require a permit" is "entirely consistent with the statute and regulations." *Id.*

The district court relied additionally on the fact that post-project emissions did not actually increase. The underlying purpose of the statutory and regulatory scheme of permitting improvements that do not increase emissions therefore appears to have been met. However, because the undisputed facts establish that DTE complied with the basic requirements for making projections, I do not rely on the district court's alternative reason for granting summary judgment.

I would affirm the district court's judgment.

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

Nos. 14-2274/2275

UNITED STATES OF AMERICA (14-2274),
Plaintiff - Appellant,

SIERRA CLUB (14-2275),
Intervenor Plaintiff - Appellant,

v.

DTE ENERGY COMPANY and DETROIT EDISON COMPANY,
Defendants - Appellees.

FILED
Jan 10, 2017
DEBORAH S. HUNT, Clerk

Before: BATCHELDER, DAUGHTREY, and ROGERS, Circuit Judges.

JUDGMENT

On Appeal from the United States District Court
for the Eastern District of Michigan at Detroit.

THIS CAUSE was heard on the record from the district court and was argued by counsel.

IN CONSIDERATION WHEREOF, it is ORDERED that thedistrict court's grant of summary judgment to DTE Energy Company is REVERSED, and the case is REMANDED for further proceedings consistent with the opinion of this court.

ENTERED BY ORDER OF THE COURT

Deborah S. Hunt, Clerk

Nos. 14-2274/2275

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

FILED
May 01, 2017
DEBORAH S. HUNT, Clerk

UNITED STATES OF AMERICA (14-2274),

Plaintiff-Appellant,

SIERRA CLUB (14-2275),

Intervenor Plaintiff-Appellant,

v.

DTE ENERGY COMPANY and DETROIT EDISON COMPANY,

Defendants-Appellees.

O R D E R

BEFORE: BATCHELDER, DAUGHTREY, and ROGERS, Circuit Judges.

The court received a petition for rehearing en banc. The original panel has reviewed the petition for rehearing and concludes that the issues raised in the petition were fully considered upon the original submission and decision of the case s. The petition then was circulated to the full court. No judge has requested a vote on the suggestion for rehearing en banc.

Therefore, the petition is denied. Judge Rogers would grant rehearing for the reasons stated in his dissent.

ENTERED BY ORDER OF THE COURT

Deb S. Hunt

Deborah S. Hunt, Clerk

UNITED STATES COURT OF APPEALS
FOR THE SIXTH CIRCUIT

Deborah S. Hunt
Clerk

100 EAST FIFTH STREET, ROOM 540
POTTER STEWART U.S. COURTHOUSE
CINCINNATI, OHIO 45202-3988

Tel. (513) 564-7000
www.ca6.uscourts.gov

Filed: May 01, 2017

Mr. F. William Brownell
Hunton & Williams
2200 Pennsylvania Avenue, N.W.
Washington, DC 20037

Re: Case No. 14-2274/14-2275, *USA v. DTE Energy Company, et al*
Originating Case No. : 2:10-cv-13101

Dear Mr. Brownell,

The Court issued the enclosed Order today in these cases.

Sincerely yours,

s/Beverly L. Harris
En Banc Coordinator
Direct Dial No. 513-564-7077

cc: Mr. Thomas A. Benson
Mr. Mark B. Bierbower
Mr. Shannon W. Fisk
Mr. Makram Bassam Jaber
Mr. Harry Margerum Johnson III
Mr. Matthew J. Lund
Mr. Brent Rosser
Mr. George Peter Sibley III
Mr. Michael J. Solo Jr.
Ms. Mary Melissa Whittle

Enclosure

Federal Register

Tuesday,
December 31, 2002

Part III

Environmental Protection Agency

40 CFR Parts 51 and 52

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR); Final Rule and Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[AD–FRL–7414–5]

RIN 2060–AE11

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is revising regulations governing the New Source Review (NSR) programs mandated by parts C and D of title I of the Clean Air Act (CAA or Act). These revisions include changes in NSR applicability requirements for modifications to allow sources more flexibility to respond to rapidly changing markets and to plan for future investments in pollution control and prevention technologies. Today's changes reflect EPA's consideration of discussions and recommendations of the Clean Air Act Advisory Committee's (CAAAC) Subcommittee on NSR, Permits and Toxics, comments filed by the public, and meetings and discussions with interested stakeholders. The changes are intended to provide greater regulatory certainty, administrative flexibility, and permit streamlining, while ensuring the current level of environmental protection and benefit derived from the program and, in certain respects, resulting in greater environmental protection.

EFFECTIVE DATE: This final rule is effective on March 3, 2003.

ADDRESSES: *Docket.* Docket No. A–90–37, containing supporting information used to develop the proposed rule and the final rule, is available for public inspection and copying between 8 a.m. and 4:30 p.m., Monday through Friday (except government holidays) at the Air and Radiation Docket and Information Center (6102T), Room B–108, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC 20460; telephone (202) 566–1742, fax (202) 566–1741. A reasonable fee may be charged for copying docket materials. *Worldwide Web (WWW).* In addition to being available in the docket, an electronic copy of this final rule will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules: *http://www.epa.gov/ttn/oarpg.*

FOR FURTHER INFORMATION CONTACT: Ms. Lynn Hutchinson, Information Transfer and Program Integration Division (C339–03), U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, telephone 919–541–5795, or electronic mail at *hutchinson.lynn@epa.gov,* for general questions on this rule. For questions on baseline emissions determination or the actual-to-projected-actual applicability test, contact Mr. Dan DeRoeck, at the same address, telephone 919–541–5593, or electronic mail at *deroeck.dan@epa.gov.* For questions on Plantwide Applicability Limitations (PALs), contact Mr. Raj Rao, at the same address, telephone 919–541–5344, or electronic mail at rao.raj@epa.gov. For questions on Clean Units, contact Mr. Juan Santiago, at the same address, telephone 919–541–1084, or electronic mail at santiago.juan@epa.gov. For questions on Pollution Control Projects (PCPs), contact Mr. Dave Svendsgaard, at the same address, telephone 919–541–2380, or electronic mail at *svendsgaard.dave@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities potentially affected by this final action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups.

Industry group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122
Petroleum Refining	291	32411
Chemical Processes	281	325181, 32512, 325131, 325182, 211112, 325998, 331311, 325188
Natural Gas Transport	492	48621, 22121
Pulp and Paper Mills	261	32211, 322121, 322122, 32213
Paper Mills	262	322121, 322122
Automobile Manufacturing	371	336111, 336112, 336712, 336211, 336992, 336322, 336312, 33633, 33634, 33635, 336399, 336212, 336213
Pharmaceuticals	283	325411, 325412, 325413, 325414

[a] Standard Industrial Classification
[b] North American Industry Classification System.

Entities potentially affected by this final action also include State, local, and tribal governments that are delegated authority to implement these regulations.

Outline. The information presented in this preamble is organized as follows:

I. Overview of Today's Final Action
A. Background
B. Introduction
C. Overview of Final Actions
1. Determining Whether a Proposed Modification Results in a Significant Emissions Increase
2. CMA Exhibit B
3. Plantwide Applicability Limitations (PALs)
4. Clean Units
5. Pollution Control Projects (PCPs)
6. Major NSR Applicability
7. Enforcement
8. Enforceability
II. Revisions to the Method for Determining Whether a Proposed Modification Results in a Significant Emissions Increase
A. Introduction
B. What We Proposed and How Today's Action Compares
C. Baseline Actual Emissions For Existing Emissions Units Other than EUSGUs
D. The Actual-to-projected-actual Applicability Test
E. Clarifying Changes to WEPCO Provisions for EUSGUs
F. The "Hybrid" Applicability Test
G. Legal Basis for Today's Action
H. Response to Comments and Rationale for Today's Actions
III. CMA Exhibit B
IV. Plantwide Applicability Limitations (PALs)
A. Introduction
B. Relevant Background
C. Final Regulations for Actuals PALs
D. Rationale for Today's Final Action on Actuals PALs
V. Clean Units

A. Introduction
B. Summary of 1996 Clean Unit Proposal
C. Final Regulations for Clean Units
D. Legal Basis for the Clean Unit Test
E. Summary of Major Comments and Responses
VI. Pollution Control Projects (PCPs)
A. Description and Purpose of This Action
B. What We Proposed and How Today's Action Compares To It
C. Legal Basis for PCP
D. Implementation
VII. Listed Hazardous Air Pollutants
VIII. Effective Date for Today's Requirements
IX. Administrative Requirements
A. Executive Order 12866—Regulatory Planning and Review
B. Executive Order 13132—Federalism
C. Executive Order 13175—Consultation and Coordination with Indian Tribal Governments
D. Executive Order 13045—Protection of Children from Environmental Health Risks and Safety Risks
E. Unfunded Mandates Reform Act of 1995
F. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 *et seq.*
G. Paperwork Reduction Act
H. National Technology Transfer and Advancement Act of 1995
I. Congressional Review Act
J. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
X. Statutory Authority
XI. Judicial Review

I. Overview of Today's Final Action

A. Background

We [1] proposed revisions to the NSR rules in a notice published in the **Federal Register** on July 23, 1996 (61 FR 38250). On July 24, 1998, we published a notice (63 FR 39857) to solicit further comment on two specific aspects of the proposed revisions. Today's **Federal Register** action announces EPA's final action on the proposed revisions for baseline emissions determinations, the actual-to-future-actual methodology, actuals PALs, Clean Units, and PCPs. We have not made final determinations on any other proposed changes to the regulations.

Today's actions finalize these changes to the regulations for both the approval and promulgation of implementation plans and requirements for preparation, adoption, and submittal of implementation plans governing the NSR programs mandated by parts C and D of title I of the Act. We also proposed conforming changes to 40 CFR (Code of Federal Regulations) part 51, appendix S, and part 52.24. Today we have not included the final regulatory language for these regulations. It is our intention to include regulatory changes that conform appendix S and 40 CFR 52.24 to today's final rules in any final regulations that set forth an interim implementation strategy for the 8-hour ozone standard. We intend to finalize changes to these sections precisely as we have finalized requirements for other parts of the program. Because these are conforming changes and the public has had an opportunity for review and comment, we will not be soliciting additional comments before we finalize them.

The major NSR program contained in parts C and D of title I of the Act is a preconstruction review and permitting program applicable to new or modified major stationary sources of air pollutants regulated under the Act. In areas not meeting health-based National Ambient Air Quality Standards (NAAQS) and in ozone transport regions (OTR), the program is implemented under the requirements of part D of title I of the Act. We call this program the ''nonattainment'' NSR program. In areas meeting NAAQS (''attainment'' areas) or for which there is insufficient information to determine whether they meet the NAAQS (''unclassifiable'' areas), the NSR requirements under part C of title I of the Act apply. We call this program the Prevention of Significant Deterioration (PSD) program. Collectively, we also commonly refer to these programs as the major NSR program. These regulations are contained in 40 CFR 51.165, 51.166, 52.21, 52.24, and part 51, appendix S.

The NSR provisions of the Act are a combination of air quality planning and air pollution control technology program requirements for new and modified stationary sources of air pollution. In brief, section 109 of the Act requires us to promulgate primary NAAQS to protect public health and secondary NAAQS to protect public welfare. Once we have set these standards, States must develop, adopt, and submit to us for approval a State Implementation Plan (SIP) that contains emission limitations and other control measures to attain and maintain the NAAQS and to meet the other requirements of section 110(a) of the Act.

Each SIP is required to contain a preconstruction review program for the construction and modification of any stationary source of air pollution to assure that the NAAQS are achieved and maintained; to protect areas of clean air; to protect Air Quality Related Values (AQRVs) (including visibility) in national parks and other natural areas of special concern; to assure that appropriate emissions controls are applied; to maximize opportunities for economic development consistent with the preservation of clean air resources; and to ensure that any decision to increase air pollution is made only after full public consideration of all the consequences of such a decision.

For newly constructed, ''greenfield'' sources, the determination of whether an activity is subject to the major NSR program is fairly straightforward. The Act, as implemented by our regulations, sets applicability thresholds for major sources in nonattainment areas [potential to emit (PTE) above 100 tons per year (tpy) of any pollutant subject to regulation under the Act, or smaller amounts, depending on the nonattainment classification] and attainment areas (100 or 250 tpy, depending on the source type). A new source with a PTE at or above the applicable threshold amount ''triggers,'' or is subject to, major NSR.

The determination of what should be classified as a modification subject to major NSR presents more difficult issues. The modification provisions of the NSR program in parts C and D are based on the definition of modification in section 111(a)(4) of the Act: the term ''modification'' means ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' That definition contemplates that, first, you will determine whether a physical or operational change will occur. If so, then you will proceed to determine whether the physical or operational change will result in an emissions increase over baseline levels.

The expression ''any physical change * * * or change in the method of operation'' in section 111(a)(4) of the Act is not defined. We have recognized that Congress did not intend to make every activity at a source subject to the major NSR program. As a result, we have previously adopted several exclusions from what may constitute a ''physical or operational change.'' For instance, we have specifically recognized that routine maintenance, repair and replacement, and changes in hours of operation or in the production rate are not considered a physical change or change in the method of

[1] In this preamble the term ''we'' refers to EPA and the term ''you'' refers to major stationary sources of air pollution and their owners and operators. All other entities are referred to by their respective names (for example, reviewing authorities.)

operation within the definition of major modification.[2]

We have likewise addressed the scope of the statutory definition of modification by excluding all changes that do not result in a ''significant'' emissions increase from a major source.[3] This regulatory framework applies the major NSR program at existing sources to only ''major modifications'' at major stationary sources.

One key attribute of the major NSR program in general is that you may ''net'' modifications out of review by coupling proposed emissions increases at your source with contemporaneous emissions reductions. Thus, under regulations we promulgated in 1980, you may modify, or even completely replace, or add, emissions units without obtaining a major NSR permit, so long as ''actual emissions'' do not increase by a significant amount over baseline levels at the plant as a whole.

Applicability of the major NSR program must be determined in advance of construction and is pollutant-specific. In cases involving existing sources, this requires a pollutant-by-pollutant determination of the emissions change, if any, that will result from the physical or operational change. Our 1980 regulations implementing the PSD and nonattainment major NSR programs thus inquire whether the proposed change constitutes a ''major modification,'' that is, a physical change or change in the method of operation ''that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.'' A ''net emissions increase'' is defined as the increase in ''actual emissions'' from the particular physical or operational change (taking into account the use of emissions control technology and restrictions on hours of operation or rates of production where such controls and restrictions are enforceable), together with your other contemporaneous increases or decreases in actual emissions.[4] In order to trigger applicability of the major NSR program, the net emissions increase must be ''significant.''[5]

Before today's changes, our regulations generally defined actual emissions as ''the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation.'' The reviewing authorities will allow use of a different time period ''upon a determination that it is more representative of normal source operation.'' We have historically used the 2 years immediately preceding the proposed change to establish a source's actual emissions. However, in some cases we have allowed use of an earlier period.

With respect to changes at existing sources, a prediction of whether the physical or operational change would result in a significant net increase in your actual emissions following the change was thus necessary. In part, this involved a straightforward and readily predictable engineering judgment—how would the change affect the emission factor or emissions rate of the emissions units that are to be changed.

Before today's changes, the regulations provided that when your emissions unit, other than an electric utility steam generating unit (EUSGU), ''has not begun normal operations,'' actual emissions equal the PTE of the unit. When you have not begun normal operations following a change, you must assume that your source will operate at its full capacity year round, that is, at its full emissions potential. This is referred to as the actual-to-potential test. You may avoid the need for an NSR permit by reducing your source's potential emissions through the use of enforceable restrictions to pre-modification actual emissions levels plus an amount that is less than ''significant''.

In 1992, we promulgated revisions to our applicability regulations creating special rules for physical and operational changes at EUSGUs. *See* 57 FR 32314 (July 21, 1992).[6] In this rule, prompted by litigation involving the Wisconsin Electric Power Company (WEPCO) and commonly referred to as the ''WEPCO rule,'' we adopted an actual-to-future-actual methodology for all changes at EUSGUs except the construction of a new electric generating unit or the replacement of an existing emissions unit. Under this methodology, the actual annual emissions before the change are compared with the projected actual emissions after the change to determine if a physical or operational change would result in a significant increase in emissions. To ensure that the projection is valid, the rule requires the utility to track its emissions for the next 5 years and provide to the reviewing authority information demonstrating that the physical or operational change did not result in an emissions increase.

In promulgating the WEPCO rule, we also adopted a presumption that utilities may use as baseline emissions the actual annual emissions from any 2 consecutive years within the 5 years immediately preceding the change.

In attainment areas, once major NSR is triggered, you must, among other things, install best available control technology (BACT) and conduct modeling and monitoring as necessary. If your source is located in a nonattainment area, you must install technology that meets the lowest achievable emissions rate (LAER), secure emissions reductions to offset any increases above baseline emission levels, and perform other analyses.

B. Introduction

Today's final regulations were proposed as part of a larger regulatory package on July 23, 1996 (61 FR 38250). That package proposed a number of changes to our existing major NSR requirements. (Please refer to the outline of that proposed rulemaking for a complete list of changes that were proposed to our existing regulations.) On July 24, 1998, we published a **Federal Register** Notice of Availability (NOA) that requested additional comment on three of the proposed changes: determining baseline emissions, actual-to-future-actual methodology, and PALs. Following the 1996 proposals, we held two public hearings and more than 50 stakeholder meetings. Environmental groups, industry, and State, local, and Federal agency representatives participated in these many discussions.

In May 2001, President Bush's National Energy Policy Development Group issued findings and key recommendations for a National Energy Policy. This document included numerous recommendations for action, including a recommendation that the EPA Administrator, in consultation with the Secretary of Energy and other relevant agencies, review NSR regulations, including administrative interpretation and implementation. The recommendation requested that we issue a report to the President on the impact of the regulations on investment

[2] *See* 40 CFR 52.21(b)(2).

[3] *See* 40 CFR 52.21(b)(23).

[4] In approximate terms, ''contemporaneous'' emissions increases or decreases are those that have occurred between the date 5 years immediately preceding the proposed physical or operational change and the date that the increase from the change occurs. *See,* for example, § 52.21(b)(3)(ii).

[5] Once a modification is determined to be major, the PSD requirements apply only to those specific pollutants for which there would be a significant net emissions increase. See, for example, § 52.21(j)(3) (BACT) and § 52.21(m)(1)(b) (air quality analysis).

[6] The regulations define ''electric utility steam generating units'' as any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts (MW) of electrical output to any utility power distribution system for sale. *See,* for example, § 51.166(b)(30).

in new utility and refinery generation capacity, energy efficiency, and environmental protection.

In response, in June 2001, we issued a background paper giving an overview of the NSR program. This paper is available on the Internet at *http://www.epa.gov/air/nsr-review/background.html.* We solicited public comments on the background paper and other information relevant to the New Source Review 90-day Review and Report to the President. During our review of the NSR program, we met with more than 100 groups, held four public meetings around the country, and received more than 130,000 written comments. Our report to the President and our recommendations in response to the energy policy were issued on June 13, 2002. A copy of this information is available at *http://www.epa.gov/air/nsr-review/.* We expect that our recommendations in response to the energy policy will be reflected in the future in various programs and regulatory actions. Today's actions implement several of those recommendations.

Today, we are finalizing five actions that we previously proposed in 1996 (three of which were re-noticed in the 1998 NOA). We are not taking final action on any of the remaining issues in the 1996 proposal at this time. We have not decided what final action we will take on those issues.

C. Overview of Final Actions

Today we are taking final action on five changes to the NSR program that will reduce burden, maximize operating flexibility, improve environmental quality, provide additional certainty, and promote administrative efficiency. These elements include baseline actual emissions, actual-to-projected-actual emissions methodology, PALs, Clean Units, and PCPs. We are also codifying our longstanding policy regarding the calculation of baseline emissions for EUSGUs. In addition, we are responding to comments we received on a proposal to adopt a methodology, developed by the American Chemistry Council (formerly known as the Chemical Manufacturers Association (CMA)) and other industry petitioners, to determine whether a source has undertaken a modification based on its potential emissions. We are including a new section in today's final rules that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. Finally, we have codified a new definition of ''regulated NSR pollutant'' that clarifies which pollutants are regulated under the Act for purposes of major NSR.

This section briefly introduces each improvement. Detailed discussions of the improvements are found in sections II through VII of this preamble.

1. Determining Whether a Proposed Modification Results in a Significant Emissions Increase

Today we are finalizing two changes to our existing major NSR regulations that will affect how you calculate emissions increases to determine whether physical changes or changes in the method of operation trigger the major NSR requirements. First, we have a new procedure for determining ''baseline actual emissions.'' That is, the relevant terminology for calculating pre-change emissions for most applications is now ''baseline actual emissions'' rather than ''actual emissions.'' You may use any consecutive 24-month period in the past 10 years to determine your baseline actual emissions. Second, we are supplementing the existing actual-to-potential applicability test with an actual-to-projected-actual applicability test for determining if a physical or operational change at an existing emissions unit will result in an emissions increase. Notwithstanding the new test, you will still have the ability to conduct an actual-to-potential type test within the new actual-to-projected-actual applicability test. In this case, you will not be subject to recordkeeping requirements that are being established and would otherwise apply as part of the new actual-to-projected actual applicability test.

For EUSGUs, we are making several changes to the existing procedures and are codifying our current policy for calculating the baseline actual emissions. That is, the baseline actual emissions for EUSGUs is the average rate, in tpy, at which that unit actually emitted the pollutant during a 2-year (consecutive 24-month) period within the 5-year period immediately preceding when the owner or operator begins actual construction. We are also retaining the option that allows the use of a different time period if the reviewing authority determines it is more representative of normal source operation.

2. CMA Exhibit B

As described in section I.C.1 above, we have decided to adopt an actual-to-projected-actual methodology, combined with a revised process to determine baseline emissions, to use in determining when sources are considered to have made a modification and are thereby subject to NSR. We are not adopting the methodology based on potential emissions as discussed in the CMA Exhibit B proposal. *See* section III of this preamble for a discussion of the comments we received on this proposal and our responses.

3. Plantwide Applicability Limitations

A PAL is a voluntary option that will provide you with the ability to manage facility-wide emissions without triggering major NSR review. We believe that the added flexibility provided under a PAL will facilitate your ability to respond rapidly to changing market conditions while enhancing the environmental protection afforded under the program.

Today we are promulgating a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap (that is, an actuals PAL), then these regulations will allow you to avoid the major NSR permitting process when you make alterations to the facility or individual emissions units. In return for this flexibility, you must monitor emissions from all of your emissions units under the PAL. The benefit to you is that you can alter your facility without first obtaining a Federal NSR permit or going through a netting review. A PAL will allow you to make changes quickly at your facility. If you are willing to undertake the necessary recordkeeping, monitoring, and reporting, a PAL offers you flexibility and regulatory certainty.

4. Clean Units

We are promulgating a new type of applicability test for emissions units that are designated as Clean Units. The new applicability test recognizes that when you go through major NSR review and install BACT or LAER, you may make any changes to the Clean Unit without triggering an additional major NSR review, if the project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or LAER and the project would not alter any physical or operational characteristics that formed the basis for the BACT or LAER determination. If the project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT or LAER or would alter any physical or operational characteristics that formed the basis for the BACT or LAER determination, you lose Clean Unit status. You may still proceed with the project without triggering major NSR review, if the increase is not a significant net emissions increase. Emissions units that have not been through major NSR may still qualify for Clean Unit status if they demonstrate that the emissions control level is comparable to BACT or LAER. Clean Unit status will be valid for up to a 10-year period. The new applicability test does not exclude consideration of physical changes or changes in the method of operation of Clean Units from major NSR, but rather changes the way emissions increases are calculated for these changes. This new applicability test therefore protects air quality, creates incentives for sources to install state-of-the-art controls, provides flexibility for sources, and promotes administrative efficiency.

5. Pollution Control Projects

Today's rule contains a new list of environmentally beneficial technologies that qualify as PCPs for all types of sources. Installation of a PCP is not subject to the major modification provisions. An owner or operator installing a listed PCP automatically qualifies for the exclusion if there is no adverse air quality impact—that is, if it will not cause or contribute to a violation of NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager (FLM) and for which information is available to the general public. The PCPs that are not listed in today's rules may also qualify for the PCP Exclusion if the reviewing authority determines on a case-specific basis that a non-listed PCP is environmentally beneficial when used for a particular application. Also, in the future, we may add to the listed PCPs through a rulemaking that provides for public notice and opportunity for comment. The PCP Exclusion allows sources to install emissions controls that are known to be environmentally beneficial. These provisions thus offer flexibility while improving air quality.

6. Major NSR Applicability

We have briefly described the new provisions for baseline actual emissions, actual-to-projected-actual methodology, PALs, and Clean Units. Sections II, IV, and V describe the new provisions in detail. These provisions offer major new changes to NSR applicability, especially regarding how a major modification is determined. The major NSR applicability provisions have developed over time and therefore have been added to the NSR rules in a piecemeal fashion. In today's final rules we are including a new section that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. For each applicability option, we describe how a major modification is determined in detail. You'll find this new applicability "roadmap" in §§ 51.165(a)(2), 51.166(a)(7), and 52.21(a)(2). To summarize, the various provisions for major modifications are now as follows.

- Actual-to-projected-actual applicability test for all existing emissions units. (Including an actual-to-potential option)
- Actual-to-potential test for any new unit, including EUSGUs.
- The Clean Unit Test for existing emissions units with Clean Unit status.
- The hybrid test for modifications with multiple types of emissions units. (Used when a physical or operational change affects a combination of more than one type of unit.)

We describe actuals PALs, which are an alternative way of complying with major NSR, in section IV of this preamble. If you have a PAL, as long as you are complying with the PAL requirements, any physical or operational changes are not major modifications.

We have revised the definition of major modification to clarify what has always been our policy—that determining whether a major modification has occurred is a two-step process. The new definition of major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: (1) A significant emissions increase of a regulated NSR pollutant; and (2) a significant net emissions increase of that pollutant from the major stationary source." We have also revised the definitions of actual emissions, emissions unit, net emissions increase, and construction. We have deleted the word "actual" as related to emissions from the definition of "construction." This change was necessary because of how the definition of "actual emissions" is used in the final rule, but the deletion is not intended to change any meaning in the term "construction." We have added new definitions for baseline actual emissions, projected actual emissions, project, and significant emissions increase. These revisions and additions implement our new provisions for major modifications under the actual-to-projected-actual applicability test, actual-to-potential test, Clean Unit Test, and hybrid test. You will find a complete discussion of the Clean Unit Test, including how modifications to Clean Units are treated, in section V of this preamble. The other tests are discussed in section II.

"Actual emissions," as the term has been historically applied, will still be used to determine air quality impacts (for example, compliance with NAAQS, PSD increments, and AQRVs) and to compute the required amount of emissions offsets.

To further clarify major NSR applicability in one location, we have moved § 51.166(i)(1) through (3) and § 52.21(i)(1) through (3) into the new applicability sections at § 51.166(a)(7) and § 52.21(a)(2). These provisions clarify that you must obtain a permit before you begin construction (including for major modifications), that the provisions apply for each regulated NSR pollutant that your source emits, and that the provisions apply to any source located in the area designated as attainment or unclassifiable (for §§ 51.166 and 52.21).

We have also added a new definition for reviewing authority that clarifies who has authority to implement major NSR programs. Reviewing authority means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under §§ 51.165 and 51.166, or the Administrator in the case of EPA-implemented permit programs under § 52.21.

7. Enforcement

As noted above, today we are taking final action on five changes to the NSR program that create alternative means of determining NSR applicability for projects that begin actual construction after these provisions become effective in your jurisdiction. If you are subsequently determined not to have met any of the obligations of these new alternatives (for example, failure to meet emissions or applicability limits, properly project emissions, and/or properly implement the PCP Exclusion or Clean Unit Test), you will be subject to any applicable enforcement provisions (including the possibility of citizens' suits) under the applicable sections of the Act. Sanctions for violations of these provisions may include monetary penalties of up to $27,500 per day of violation, as well as the possibility of injunctive relief, which may include the requirement to install air pollution controls.

8. Enforceability

This rule uses several terms related to enforceability of particular provisions. A requirement is "legally enforceable" if some authority has the right to enforce the restriction. Practical enforceability for a source-specific permit will be achieved if the permit's provisions specify: (1) A technically-accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance, including appropriate monitoring, recordkeeping, and reporting. For rules and general permits that apply to categories of sources, practicable enforceability additionally requires that the provisions: (1) Identify the types or categories of sources that are covered by the rule; (2) where coverage is optional, provide for notice to the permitting authority of the source's election to be covered by the rule; and (3) specify the enforcement consequences relevant to the rule.[7,8] ''Enforceable as a practical matter'' will be achieved if a requirement is both legally and practically enforceable.

Note that we continue to require offsets to be federally enforceable. ''Federal enforceability'' means that not only is a requirement practically enforceable, as described above, but in addition, ''EPA must have a direct right to enforce restrictions and limitations imposed on a source to limit its exposure to Act programs.''[9] Also note that, for computing baseline actual emissions for use in determining major NSR applicability or for establishing a PAL, you must consider ''legally enforceable'' requirements. A requirement will be legally enforceable if the Administrator, State, local or tribal air pollution control agency has the authority to enforce the requirement irrespective of its practical enforceability.

In our existing regulations that are unamended by today's action, the term ''federally enforceability'' still appears. In 1995, the court in *Chemical Manufacturers Ass'n* v. *EPA* remanded the definition of PTE in the major NSR program to EPA. No. 89–1514 (D.C. Cir. Sept. 150 1995). Because the court vacated the requirements in the nationwide rules, the term federal enforceability as it relates to PTE is not in effect (pending final rule making by the Agency) in the Federal rules. The decision, however, did not address the term ''federally enforceable'' as used in SIPs, because that issue was not before the court.

II. Revisions to the Method for Determining Whether a Proposed Modification Results in a Significant Emissions Increase

A. Introduction

Today we are finalizing two sets of amendments to our existing major NSR regulations that provide another way in which you may calculate emissions increases to determine whether certain types of physical changes or changes in the method of operation (physical or operational changes) of an existing emissions unit trigger the major NSR requirements.[10] The first set of amendments relates to the way in which you will determine your baseline actual emissions for such emissions units in accordance with a new definition of ''baseline actual emissions.'' *See,* for example, new § 52.21(b)(48). We will be allowing you to use any consecutive 24-month period during the 10-year period prior to the change to determine your baseline actual emissions for existing emissions units (other than EUSGUs). The second set of amendments replaces the existing actual-to-potential and actual-to-representative-actual-annual emissions applicability tests for existing emissions units (including EUSGUs) with an actual-to-projected-actual applicability test for determining if a physical or operational change will result in an emissions increase at such units. (Notwithstanding this new test, the actual-to-potential methodology is still available at your option under the new applicability tests.) The new procedure for determining your pre-change baseline actual emissions will not apply to EUSGUs.[11] Instead, for EUSGUs we are retaining the existing procedures for determining the baseline actual emissions.[12] *See,* for example, existing § 52.21(b)(33). We are also affirming our current method used for calculating the baseline actual emissions for EUSGUs (allowing any consecutive 2 years in the past 5 years, or another more representative period) by codifying it in the NSR regulations. *See,* for example, new § 52.21(b)(48).

For existing emissions units other than EUSGUs, the changes we are making to the method for calculating a unit's baseline actual emissions will apply only for the following three purposes.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test.
- For netting, to determine the pre-change baseline actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period.
- For PALs, to establish the PAL emissions cap.

Today's new procedures for calculating baseline actual emissions and for the actual-to-projected-actual applicability test should not be used when determining a source's actual emissions on a particular date as may be used for other NSR-related requirements. Such requirements include, but are not limited to, air quality impacts analyses (for example, compliance with NAAQS, PSD increments, and AQRVs) and computing the required amount of emissions offsets. For each of these requirements, the existing definition of ''actual emissions'' continues to apply. This is discussed in greater detail in section II.D.9.

We believe that these changes will greatly improve the major NSR program by responding to industry concerns with our existing methodology without compromising air quality. One common complaint about the current emissions baseline process is that you have a limited ability to consider the operational fluctuations associated with normal business cycles when establishing baseline actual emissions unless your reviewing authority agrees that another period is ''more representative of normal source

[7] See memorandum, ''Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit,'' signed by John Seitz and Robert Van Heuvelen, Jan. 22, 1996 at 5–6 and Attachment 4, available on the Web as *http://www.epa.gov/rgytgrnj/programs/artd/air/title5/t5memos/pottoemi.pdf.* More detailed guidance on practical enforceability is contained in the memorandum.

[8] The Agency has frequently used the term ''practicably enforceable'' and ''practical enforceability,'' interchangeably. There is no difference in the meaning of these terms.

[9] *See* generally memorandum, ''Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act,'' signed by John Seitz and Robert Van Heuvelen, Jan. 25, 1995, at 2–3.

[10] By definition, the modification of an existing source is potentially subject to major NSR only if that existing source is ''major.'' In addition, when an existing ''minor'' source makes a physical or operational change that by itself is major, that change constitutes a major stationary source that is subject to major NSR. *See*, for example, § 52.21(b)(1)(*c*).

[11] For NSR purposes, the definition of ''electric utility steam generating unit'' means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility. See, for example, § 52.21(b)(31). Reference in this notice to utility units is meant to include all emissions units covered by this definition.

[12] We promulgated special applicability rules for physical and operational changes at EUSGUs in 1992. *See* 57 FR 32314 (July 21, 1992).

ED_001598_00009761

operation.'' [13] By extending the time period from which you may establish your baseline actual emissions, the new procedures should reflect the emissions levels that occur during a normal business cycle, without requiring you to demonstrate to your reviewing authority that another period is ''more representative of normal source operations.''

Commenters also believe that the current methodology requires many changes made to existing equipment to go through major NSR, without taking into account operating history, even when such changes will not result in increased pollution to the environment. Our new applicability requirements address these commenters' concerns and will focus limited resources more effectively.

We are also modifying the way you may determine whether emissions at existing units (including EUSGUs) will increase, by allowing you to use projected actual emissions for purposes of this determination. Under this approach, in circumstances where there is a reasonable possibility that a project that is not part of a major modification may result in a significant increase of a regulated NSR pollutant, before beginning actual construction, you may choose to make and record a projection of post-change emissions of that pollutant from changed units.[14]

To make this projection, you must use the maximum annual rate at which the changed units are projected to emit the pollutant in any of the 5 calendar years following the time the unit resumes regular operations after the project (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). You then use these projections to calculate whether the project will result in a significant emissions increase. In making this calculation, you could exclude any emissions that the unit could have accommodated before the change and that are unrelated to the project. You could also exclude emissions resulting from increased utilization due to demand growth that the unit could have accommodated before the change.

With respect to the covered changes, if you use this procedure, you are required to track post-change annual emissions of the units in tpy for the next 5 years (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). At the end of each year, if post-change annual emissions exceed the baseline actual emissions by a significant amount, and differ from your projections, you must submit a report to the reviewing authority with that information within 60 days after the end of the year.

Instead of relying on projected actual emissions, you may instead elect to use the unit's PTE, in tpy. In that case, you need not track or report post-change emissions.

We are also revising the procedures for projecting future emissions for EUSGUs to conform with these new procedures and consolidate the EUSGU and non-EUSGU procedures into a single set of provisions. As a result of our 1992 rulemaking, EUSGUs have available to them a similar set of procedures. We believe the procedures we are implementing for other units represent a sensible refinement of the rules we promulgated in 1992 and that we should make these procedures available to all existing units. We do, however, impose two requirements on EUSGUs beyond those we impose on other units. First, with respect to covered projects, EUSGUs that project post-change emissions will have to submit a copy of their projections to their reviewing authority before beginning actual construction. You will not be required to obtain any kind of determination from the reviewing authority before proceeding with construction. Second, we are requiring that if you project post-change emissions for your EUSGUs, you must send a copy of your tracked emissions to your reviewing authority, without regard to whether these emissions have increased by a significant amount or exceed your projections. The effect of this consolidation is that we make minor changes to the existing procedures for EUSGUs. For example, you must project emissions for EUSGUs on a 12-month basis, rather than the current approach of projecting average annual emissions for the 2 years immediately following the change. Also, you need only make and report a projection for EUSGUs when there is a reasonable possibility that the given project may result in a significant emissions increase.

By allowing you to use today's new version of the actual-to-projected-actual applicability test to evaluate modified existing emissions units, we expect that fewer projects will trigger the major NSR permitting requirements. Nonetheless, we believe that the environment will not be adversely affected by these changes and in some respects will benefit from these changes. The new test will remove disincentives that discourage sources from making the types of changes that improve operating efficiency, implement pollution prevention projects, and result in other environmentally beneficial changes. Moreover, the end result is that State and local reviewing authorities can appropriately focus their limited resources on those activities that could cause real and significant increases in pollution.

In addition, today's changes provide benefits to the public and the environment through the improved recordkeeping and reporting requirements as discussed above. We believe that these added recordkeeping and reporting measures will provide the information necessary for reviewing authorities to assure that such changes are made consistent with the CAA requirements. The new rule also does not affect the way in which a source's ambient air quality impacts are evaluated. Altogether, we believe that today's regulatory amendments focus on the types of changes occurring at existing emissions units that are more likely to result in significant contributions to air pollution.

B. What We Proposed and How Today's Action Compares

1. July 23, 1996 Notice of Proposed Rulemaking (NPRM)

In 1996, we proposed to amend the NSR rules to allow States to use, among other things, a new test as an alternative to the actual-to-potential test for determining the applicability of the NSR requirements when you wish to make modifications at an existing major stationary source. The proposed test was intended to apply exclusively to modifications of existing emissions units at major stationary sources—not to new emissions units. As described more completely below, the proposed test involved changes to the procedures for calculating an emissions unit's pre-change (baseline) actual emissions and post-change (future) actual emissions. The method would have also required you to monitor and report future emissions from certain modified

[13] The definition of ''actual emissions'' requires that a unit's actual emissions be based on a consecutive 24-month period immediately preceding the particular change. Also, however, it directs the reviewing authority to allow the use of another time period upon a determination that it is more representative. This procedure continues to be appropriate under the pre-existing regulation and for other NSR purposes, such as determining a source's ambient impact against the PSD increments, and we continue to require its use for such purposes.

[14] Note that we plan, in the near future, to issue a Notice of Proposed Rulemaking that will address the issue of ''debottlenecking.'' In today's rulemaking, we do not intend to change current requirements related to ''debottlenecking.'' Use of the term ''changed unit'' should not be interpreted as a change to those requirements.

emissions units, based on the monitoring and reporting requirements adopted under the WEPCO amendments.

Baseline actual emissions. In our 1996 NPRM, we proposed to change the definition of baseline emissions from the average annual rate of actual emissions during the 2-year period preceding the date of the modification to the annual rate associated with the highest level of utilization from any consecutive 12-month period during the 10-year period preceding the date of the modification, adjusted for any more stringent limits that may have been imposed since the end of the 12-month period selected. The proposed method was intended to be used for calculating baseline actual emissions for any existing emissions unit, including EUSGUs, by replacing both the original method (that was part of the actual-to-potential test) and the 2-in-5-years method (as adopted under the WEPCO for modified EUSGUs).

As indicated above, the proposed procedure also would have required you to take into account any legally enforceable constraints imposed on the facility since the selected 12-month time frame, and currently in effect. Thus, you would generally have been required to calculate the modified emissions unit's baseline actual emissions by using the appropriate utilization level from the selected 12-month period, in combination with the emissions unit's current enforceable emission factors. Such enforceable emission factors would have included current Federal and State limits, such as RACT (Reasonably Available Control Technology), MACT (Maximum Achievable Control Technology), BACT, LAER, and New Source Performance Standards (NSPS), as well as enforceable limits resulting from any voluntary reductions you may have taken (for example, for netting, offsets, or Emission Reduction Credits (ERCs)). Also, you would have had to consider any operational constraints that are enforceable, such as production limits, fuel use limits, or limits to the number of hours per day or days per year at which the unit modified, or affected by such modification, could operate.

Finally, we indicated that it was not our intent to extend the 5-year contemporaneous period (for considering creditable emissions increases and decreases as part of the netting calculus), even if we established a 10-year baseline look back period.

Post-change actual emissions. In the 1996 proposal, we proposed to extend the availability of the actual-to-future-actual emissions method, established under the WEPCO amendments exclusively for EUSGUs, to predict the future actual emissions from any emissions unit undergoing a physical or operational change. Thus, we proposed extending availability of the definition of ''representative actual annual emissions'' to all emissions units undergoing a physical or operational change. This definition would have provided the basis for you to project an emissions unit's future actual emissions, excluding any emissions increases caused by demand growth or other independent factors, when determining whether the change at issue will increase emissions over the baseline levels.[15]

The proposal also retained the WEPCO provision requiring that, for any modified emissions unit using the actual-to-future-actual test, you must submit annually for 5 years after the change sufficient records to demonstrate that the change has not resulted in a significant emissions increase over the baseline levels. As a safeguard, the WEPCO rule also provides that this tracking period could be extended to 10 years when the reviewing authority is concerned that the first 5 years will not be representative of normal source operation. We sought comments on numerous issues, including whether any changes should be made to the 5-year tracking requirement or to the demand growth exclusion in the event that we decided to broaden use of the actual-to-future-actual test for modifications to any existing emissions unit.

2. July 24, 1998 Notice of Availability

In 1998, we announced that comments received on the 1996 proposal and changed circumstances had caused us to ask whether we should reconsider some of the aspects of the proposed changes to the ''major modification'' applicability test. The 1998 NOA set forth for public comment an additional applicability test. In brief, the alternative presented for additional comment would have: (1) Retained the actual-to-future-actual test for EUSGUs and applied it to all source categories; (2) made binding for a 10-year period the emissions levels used in projecting future actual emissions following the modification for all source categories; and (3) eliminated the demand growth exclusion for calculating a modified emissions unit's future actual emissions.

Consistent with the 1996 NPRM, this alternative methodology would have applied to any existing emissions unit at a major stationary source for which you might plan a non-routine physical or operational change. The methodology would have required you first to determine which emissions units were being changed, or were affected by the change, then to calculate those units' baseline actual emissions based on the highest consecutive 12 months of source operation during the past 10 years, adjusted to reflect current emission factors.

The second step involved the forecast of future emissions resulting from the physical or operational change. Under this calculation of future actual emissions, one would not have been allowed to exclude predicted capacity utilization increases that were due to demand growth. If the difference between the pre-change and post-change actual emissions equaled or exceeded the significant emissions rate defined for a particular pollutant, major NSR would have been triggered (unless you took enforceable limits to keep the increase below significant levels or were otherwise able to net out of review using creditable, contemporaneous emissions increases and decreases occurring at your facility). If the difference between baseline and future actual emissions did not exceed the applicable significant emissions rate, your facility would not be subject to major NSR, but you would have been required to accept a temporary emissions cap based on the predicted future actual emissions for each affected pollutant at the emissions units being modified or affected by the modification.

The temporary cap would have become an enforceable condition of a preconstruction permit. Also, the sole purpose of the temporary cap would have been to make sure that the physical or operational change did not result in a significant emissions increase, and the cap would have applied to those emissions units for at least 10 years after the changes were completed. You would also have been required to supply information annually to demonstrate that the future actual emissions did not exceed the applicable emissions caps during the 10-year period following the modification.

3. Summary of Major Changes in the Final Rule

Today's action amends the existing NSR regulations to provide you with a common applicability test for all existing emissions units—the actual-to-projected-actual applicability test. This test has changed in some ways from both the 1996 NPRM and the 1998 NOA. As described in greater detail in sections

[15] This method, as well as the WEPCO amendments as a whole, was limited to modifications of existing EUSGUs and did not apply to the addition of a new emissions unit or the replacement of an existing unit.

II.C and II.D below, the key features of the methodology are as follows.

• If you are an existing emissions unit (other than an EUSGU), you will determine the pre-change (baseline) actual emissions by calculating an average annual emissions rate, in tpy, using any consecutive 24 months during the 10-year period immediately preceding the change. This rate must be adjusted downward to reflect any legally enforceable emission limitations imposed after the selected baseline period.

• We are codifying the ''2-in-5-years'' presumption for calculating the baseline actual emissions for EUSGUs.

• If you are an existing emissions unit (including EUSGUs), you will estimate post-change emissions (projected actual emissions), in tpy, to reflect any increase in annual emissions that may result from the proposed change. You should exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the baseline period and that is also unrelated to the particular project, including any increased utilization due to product demand growth. You must make the projection before you begin actual construction. When using this method, you must record the projection and certain other information in circumstances where there is a reasonable possibility that a change may result in a significant emissions increase. In addition, EUSGUs must send a copy of the projections and other information to your reviewing authority before beginning actual construction.

• If, for a project at an existing emissions unit (other than an EUSGU) at a major stationary source, you elect to project your post-change emissions, we are also requiring you to maintain information on these emissions, for 5 years following a physical or operational change, or in some cases for 10 years depending on the nature of the change. If your annual emissions exceed the baseline actual emissions by a significant amount and also exceed your projection, you must report this information to your reviewing authority within 60 days after the end of the year.

• If you project post-change emissions for EUSGUs, you must report these emissions to your reviewing authority within 60 days after the end of the year without regard to whether such emissions exceed the baseline actual emissions or projected actual emissions for a period of 5 years (or in some cases 10 years, depending on the nature of the change).

• Instead of projecting your post-change emissions, for all existing emissions units you may instead project post-change emissions on the basis of each unit's post-change PTE. If you use this method, you need not record your projections or track or report post-change emissions.

As discussed earlier, our prior regulations provide that when your emissions unit, other than an EUSGU, ''has not begun normal operations, ''actual emissions equal the PTE of the unit. There have been considerable number issues raised with this approach. For example, using PTE as a measure of post-change emissions automatically attributes all possible emissions increases to the change. There are many cases, however, where this simply is not true. Moreover, when the actual-to-potential test is applied, it is automatically assumed that the emissions unit has not begun normal operations after the change period. In many such cases, however, the changed unit as a practical matter will function essentially as it did before the change. We are, therefore, allowing all existing emissions units to use an actual-to-projected-actual applicability test. Accordingly, we are generally eliminating the term ''begun normal operations'' from the determination of whether a change results in a significant emissions increase.[16]

For essentially the same reasons, while our 1992 rules did not authorize use of projections in evaluating whether replacement of an existing emissions unit (which we understood to require application of the NSPS 50 percent cost threshold) constitutes a major modification, upon reflection we have decided this exception to the availability of the actual-to-projected-actual applicability test is also unnecessary. In our 1980 rulemaking, we decided against applying PSD to ''reconstruction,'' even of entire sources, on the grounds that, as to existing sources that would not otherwise be subjected to PSD review as a major modification (*i.e.*, such source would not cause a significant net emissions increase), changes that had no emission consequences should not be subject to PSD regardless of their magnitude.[17]

In addition, we now believe that, as with modified units, the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit. In contrast, sources adding ''new'' units that do not qualify as replacement units must project that the future emissions of the new unit equal its PTE, effectively applying the ''actual-to-potential'' test because there is no relevant historical data that could be used to establish an actual emissions baseline or projection of future actual emissions for such new units.

For these reasons, we have eliminated the requirement that replaced or reconstructed units be evaluated as to whether they constitute major modifications on an actual-to-potential basis. Instead, you may compare an emission unit's baseline actual emissions with your projected actual emission in measuring whether the replacement or reconstruction has resulted in a significant emissions increase. You must treat these emissions units as modifications only if the replacement or reconstruction of the unit results in a signficant increase so measured.[18]

[16] We do make use of the term ''resumes regular operations'' (as opposed to ''normal operations'') in the final rule, but that term has a very different meaning and we are using it for an entirely different purpose. Specifically, we are not using the term for purposes of determining whether a change results in a significant emissions increase. Rather, we use it only to identify the date on which the owner or operator must begin tracking emissions of changed units when using the actual-to-projected-actual method.

[17] The 1980 rulemaking also discussed that ''reconstruction'' would have only been applied on a plantwide basis and EPA believed that there would be few instances of plantwide reconstructions.

[18] For simplicity, we state this rule without addressing whether the replacement or reconstruction has resulted in a significant net emissions increase, but under our two-step approach for evaluating whether a change constitutes a major modification, a significant net emissions increase would of course also be required. We have also retained the term ''representative of normal operations'' in the context of an EUSGU's option to seek use of a different baseline period, but there the question whether to seek such use is at the source's option, obviating many of the difficulties with it in other contexts.

C. Changes to the Procedures for Calculating the Pre-Change Baseline Actual Emissions for Existing Emissions Units Other Than EUSGUs

1. Under Today's New Requirements, How Should I Calculate the Pre-Change Baseline Actual Emissions for an Existing Emissions Unit That Is Not an EUSGU?

When you calculate the baseline actual emissions for an existing emissions unit (other than an EUSGU), you may select any consecutive 24 months of source operation within the past 10 years. Using the relevant source records for that 24-month period, including such information as the utilization rate of the equipment, fuels and raw materials used in the operation of the equipment, and applicable emission factors, you must be able to calculate an average annual emissions rate, in tpy, for each pollutant emitted by the emissions unit that is modified, or is affected by the modification.

The new requirements prohibit you from counting as part of the baseline actual emissions any pollution levels that are not allowed under any legally enforceable limitations and that apply at the time of the project. Therefore, you must identify the most current legally enforceable limits on your emissions unit. If these legally enforceable emission limitations and operating restrictions are more stringent than those that applied during the 24-month period, you must adjust downward the average annual emissions rate that you calculated from the consecutive 24-month period to reflect these current restrictions. (*See* section II.C.5 of this preamble for further discussion of the adjustment that you may need to make.)

In summary, when the average annual emissions rate that you originally calculated is still legally achievable (see discussion below), then your baseline actual emissions will be the same as the average annual emissions rate calculated from the 24-month period. If it is not, you must adjust it downward so that it does not reflect emissions that are no longer legally allowed.

2. Can Existing Emissions Units (Other Than EUSGUs) Still Use a ''More Representative Time Period'' for Selecting the Baseline Actual Emissions?

No, under today's new requirements neither you nor your reviewing authority will have the authority to select another period of time from which to calculate your baseline actual emissions. You must select a 24-month period within the 10-year period before the physical or operational change.

3. From What Point in Time Is the 10-Year Look Back Measured?

If you believe that you will need either a major or minor NSR permit to proceed with your proposed physical or operational change, then you must use the 10-year period immediately preceding the date on which you submit a complete permit application. If, however, you believe that the physical or operational change(s) you plan to make will not result in either a significant emissions increase from the project or a significant net emissions increase at your major stationary source (that is, your project will not be a major modification), and you are not otherwise required to obtain a minor NSR permit before making such change, then you must use the 10-year period that immediately precedes the date on which you begin actual construction of the physical or operational change.

4. What if, for an Existing Emissions Unit (Other Than an EUSGU), I Do Not Have Adequate Documentation for Its Operation for the Past 10 Years?

Your ability to use the full 10 years of the look back period will depend upon the availability of relevant data for the consecutive 24-month period you wish to select. The data must adequately describe the operation and associated pollution levels for the emissions units being changed. If you do not have the data necessary to determine the units' actual emission factors, utilization rate, and other relevant information needed to accurately calculate your average annual emissions rate during that period of time, then you must select another consecutive 24-month period within the 10-year look back period for which you have adequate data.

5. For an Existing Unit (Other Than EUSGUs), When Must I Adjust My Calculation of the Pre-Change Baseline Actual Emissions?

Today's amendments require you to adjust the average annual emissions rate derived from the selected 24-month period under certain circumstances. Specifically, you must adjust downward this average annual rate if any legally enforceable emission limitations, including but not limited to any State or Federal requirements such as RACT, BACT, LAER, NSPS, and National Emission Standards for Hazardous Air Pollutants (NESHAP), restrict the emissions unit's ability to emit a particular pollutant or to operate at levels that existed during the selected 24-month period from which you calculate the average annual emissions rate. For example, assume that during the selected consecutive 24-month period you burned fuel oil and you were subjected to a sulfur limit of 2 percent sulfur (by weight). Today, you are only allowed to burn fuel oil with a sulfur content of 0.5 percent or less. Consequently, you would be required to adjust your preliminary calculation of baseline actual emissions for sulfur dioxide (SO_2) (that is, substitute the lower sulfur limit into the emissions calculation, yielding a 75 percent reduction in the emissions rate from the initial calculation) to reflect the current restriction allowing only 0.5 percent sulfur in fuel oil. The original average annual utilization rate would not be adjusted unless a more stringent legally enforceable operational limitation has since been imposed that restricts that rate.

You must also adjust for legally enforceable emission limitations you may have voluntarily agreed to, such as limits you may have taken in your permit for netting, emissions offsets, or the creation of ERCs. Also, you must adjust your emissions from the 24-month period if a raw material you used during the baseline period is now prohibited. For example, you may have used a paint with a high solvent concentration during a portion of the consecutive 24-month period. Today, you are prohibited from using that particular paint. You must then adjust your emissions rate to reflect the raw material restriction.

6. How Should I Calculate the Baseline Actual Emissions for Emissions Units (Other Than EUSGUs) That Use Multiple Fuels or Raw Materials?

For an emissions unit that is capable of burning more than one type of fuel, you must relate the current emission factors to the fuel or fuels that were actually used during the selected 24-month period. For example, when calculating the baseline actual emissions for an emissions unit that burned natural gas for a portion of the 24-month period and fuel oil for the remainder, you must retain that fuel apportionment (for example, natural gas to fuel oil ratio), but you must also use the current legally enforceable emission factors for natural gas and fuel oil, respectively, to calculate the baseline actual emissions. If, however, you are no longer allowed or able to use one of those fuel types, then you must make your calculations assuming use of the currently allowed fuel for the entire 24-month period. You must use the same approach for emissions units that use multiple feedstock or raw materials, which may vary in use during the unit's ongoing production process.

7. How Should I Calculate the Baseline Actual Emissions for Construction Projects That Involve Multiple Units?

Today's new requirements require that you select the same single consecutive 24-month period within the 10-year look back period to calculate the baseline actual emissions for all existing emissions units that will be changed. *See,* for example, new § 52.21(b)(48)(ii)(*e*). The result will be that the baseline actual emissions for each affected pollutant will be based on the same consecutive 24-month period as well.

You will have the option to select the single 24-month period that best represents the collective level of operation (and emissions) for your existing emissions units.

If a particular existing emissions unit did not yet exist during the 24-month period you select to calculate the baseline actual emissions, you must count that emissions unit's emissions rate as zero for that full period of time. If an emissions unit operated for only a portion of the particular 24-month period that you select, you must calculate its average annual emissions rate using an emissions rate of zero for that portion of time when the unit was not in operation.

For new emissions units (a unit that has existed for less than 2 years) that will be changed by the project, the baseline actual emissions rate is zero if you have not yet begun operation of the unit, and is equal to the unit's PTE once it has begun to operate.

8. Am I Able To Apply Today's Changes for Calculating the Baseline Actual Emissions to Other Major NSR Requirements?

No, as stated in section II.A, you are only allowed to use the new baseline methodology in today's rule for three specific purposes involving existing emissions units as follows.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test
- For netting, to determine the pre-change actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period. You may select separate baseline periods for each contemporaneous increase or decrease.
- For PALs, to establish the PAL level.

If you determine that the modification of your source is a major modification, you must revert to using the existing definition of ''actual emissions'' to determine your source's actual emissions on a particular date to satisfy all other NSR permitting requirements, including any air quality analyses (for example, compliance with NAAQS, PSD increments, AQRVs) and the amount of emissions offsets required.

For example, when you must determine your source's compliance with the PSD increments following a major modification, you must still use the allowable emissions from each emissions unit that is modified, or is affected by the modification. An existing source's contribution to the amount of increment consumed should be based on that source's actual emissions rate from the 2 years immediately preceding the date of the change, although the reviewing authority shall allow the use of another 2-year period if it determines that such period is more representative of that source's normal operation. *See,* for example, § 52.21(b)(21)(ii).

Also, any determination of the amount of emissions offset that must be obtained by a major modification subject to the nonattainment NSR requirements under § 51.165(a) should be based on calculations using the existing definitions of ''actual emissions'' and ''allowable emissions.'' See new § 51.165(a)(3)(ii)(H).

D. The Actual-to-Projected-Actual Applicability Test for Physical or Operational Changes to Existing Emissions Units Including EUSGUs

1. How are post-change actual emissions calculated under today's revised rule?

Today, we are amending the major NSR rules to enable you to use an applicability test that is similar to the applicability test that currently applies to EUSGUs (that is, the actual-to-representative-actual-annual emissions test). The new test allows you to project the post-change emissions of all modified existing emissions units (including EUSGUs) in the same manner. That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in tpy, that reflects the maximum annual emissions rate that will occur during any one of the 5 (or in some circumstances 10) years immediately after the physical or operational change. The first year begins on the day the emissions unit resumes regular operation following the change and includes the 12 months after this date. This projection of the unit's annual emissions rate following the change is defined as the ''projected actual emissions'' (see, for example, § 52.21(b)(48)), and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24-month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the emissions unit's operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions unit's likely post-change capacity utilization. In calculating the projected actual emissions, you should consider both the expected and the highest projections of the business activity that you expect could be achieved and that are consistent with information your company publishes for business-related purposes such as a stockholder prospectus, or applications for business loans. From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. Once the appropriate subtractions have been made, the final value for the projected actual emissions, in tpy, is the value that you compare to the baseline actual emissions to determine whether your project will result in a significant emissions increase.

The adjustment to the projected actual emissions allows you to exclude from your projection only the amount of the emissions increase that is not related to the physical or operational change(s). In comparing your projected actual emissions to the units' baseline actual emissions, you only count emissions increases that will result from the project. For example, as with the electric utility industry, you may be able to attribute a portion of your emissions increase to a growth in demand for your product if you were able to achieve this higher level of production during the consecutive 24-month period you selected to establish the baseline actual emissions, and the increased demand for the product is unrelated to the change.

For Clean Units, if a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, then no emissions increase will occur.

For new units, however, you must continue to calculate post-change emissions on the basis of a unit's PTE.

2. Will My Projection of Projected Actual Emissions Become an Enforceable Emission Limitation as Suggested in the 1998 NOA?

No, we did not adopt such a requirement. If you have an existing emissions unit and your project results in an increase in annual emissions that exceeds the baseline actual emissions by a significant amount, and differs from your projection of post-change emissions that you were required to calculate and maintain records of, then you must report this increase to your reviewing authority within 60 days after the end of the year. Since modified EUSGUs are required to report their post-change annual emissions to the reviewing authority annually, any occurrence of a significant increase will be covered under that report for the affected calendar year. *See* section II.D.6 of this preamble for a more detailed discussion of the reporting requirements.

3. How Do I Determine How Long My Post-Change Emissions Will Be Tracked To Ensure That My Project Is Not a Major Modification?

Generally, your projected actual emissions must be tracked against your facility's post-change emissions for 5 years following resumption of regular operations whether you are an EUSGU or other type of existing emissions unit. We will presume that any increases that occur after 5 years are not associated with the physical or operational changes. However, you may be required to track emissions for a longer period of time under the following circumstances. If you are an existing emissions unit and one of the effects of your physical or operational change(s) is to increase a unit's design capacity or PTE, you must track your emissions for a period of 10 years after the completion of the project. This extended period allows for the possibility that you could end up using the increased capacity more than you projected and such use might lead to significant emissions increases.

4. What Are the Reporting and Recordkeeping Requirements for Projects?

Reporting and recordkeeping for a project is required when three criteria are met: (1) You elect to project post-change emissions rather than use PTE; (2) there is a reasonable possibility that the project will result in a significant emissions increase; and (3) the project will not constitute a major modification. In such circumstances, you must document and maintain a record of the following information: a description of the project; an identification of emissions units whose emissions could increase as a result of the project; the baseline actual emissions for each emissions unit; and your projected actual emissions, including any emissions excluded as unrelated to the change and the reason for the exclusion. In addition, if your project increase is significant, you must record your netting calculations if you use emissions reductions elsewhere at your major stationary source to conclude that the project is not a major modification. For covered projects, you must record this information before beginning actual construction. If you are an EUSGU, you must also send this information to your reviewing authority before beginning actual construction. Note, however, that if you chose to use potential emissions as your projection of post-change emissions, you are not required to maintain a record of this decision.

In addition, today's final rules require you to maintain emissions data for all emissions units that are changed by the project. You must maintain this information for 5 years, or 10 years if applicable. The information you must maintain may include continuous emissions monitoring data, operational levels, fuel usage data, source test results, or any other readily available information of sufficient accuracy for the purpose of determining an emissions unit's post-change emissions.

If you are an EUSGU, you must report this information to your reviewing authority within 60 days after the end of any year in which you are required to generate such information. Other existing units must report to the reviewing authority any increase in the post-change annual emissions rate when that rate: (1) Exceeds the baseline actual emissions by a significant amount, and (2) differs from the projection that was calculated before the change. See, for example, new § 52.21(r)(6)(iii).

In addition to the reporting requirements discussed above, you are also obligated to ensure that the necessary emissions information you are required to maintain is available for examination upon request by the reviewing authority or the general public.

5. How Do Today's Changes Affect the Netting Methodology for Existing Emissions Units (Other Than EUSGUs)?

If your calculations show that a significant emissions increase will result from a modification, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to ''net out'' of review, that is, show that the net emissions increase at the major stationary source will not be significant. The contemporaneous time period will not change under the Federal PSD program as a result of today's action. That is, creditable increases and decreases in emissions that have occurred between the date 5 years before construction of the particular change commences and the date the increase from that change occurs are contemporaneous. *See* § 52.21(b)(3)(ii). States will continue to have some discretion in defining ''contemporaneous'' for their own NSR programs.

Although we are not changing our definition of ''contemporaneous,'' today's action allows existing emissions units (other than EUSGUs) to calculate the baseline actual emissions for each contemporaneous event using the 10-year look back period. That is, you can select any consecutive 24-month period during the 10-year period immediately preceding the change occurring in the contemporaneous period to determine the baseline actual emissions for each creditable emissions change. Generally, for each emissions unit at which a contemporaneous emissions change has occurred, you should use the 10-year look back period relevant to that change.[19] When evaluating emissions increases from multi-unit modifications, if more than one emissions unit was changed as part of a single project during the contemporaneous period, you may select a separate consecutive 24-month period to represent each emissions unit that is part of the project. In any case, the calculated baseline actual emissions for each emissions unit must be adjusted to reflect the most current emission limitations (including operational restrictions) applying to that unit. ''Current'' in the context of a contemporaneous emissions change refers to limitations on emissions and source operation that existed just prior to the date of the contemporaneous change.

E. Clarifying Changes to WEPCO Provisions for EUSGUs

The method you use to calculate the baseline actual emissions for an existing EUSGU to determine whether there is a

[19] Your ability to use the full 10 years for calculating any contemporaneous emissions change is contingent upon the availability of valid and sufficient source information for the selected 24-month period. *See*, for example, new § 52.21(b)(48)(ii)(*f*).

significant emissions increase from a physical or operational change at an EUSGU, and to determine whether a significant net emissions increase will occur at the major stationary source, will not change as a result of today's final rulemaking. The rule provides that for an existing EUSGU you may calculate the baseline actual emissions as the average annual emissions (tpy) of the emissions unit using any 2-year period out of the 5 years immediately preceding the modification. (This was set out as a presumption in the preamble for the 1992 WEPCO amendments.) This rule recognizes the ordinary variability in demand for electricity. *See,* for example, new § 52.21(b)(21)(ii).

For example, a cold winter or hot summer will result in high levels of demand while a relatively mild year will produce lower demand. By allowing a utility to use any consecutive 2 years within the past 5, the rule recognizes that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By allowing utilities to use as a baseline any consecutive 2 years in the last 5 years, these types of fluctuations in operations can be more realistically considered.

The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

In an August 6, 2001 letter,[20] we addressed the issue of whether combined cycle gas turbines (the gas turbines and waste heat recovery components) came within the definition of ''electric utility steam generating units'' for the purpose of determining whether such units are eligible to use the WEPCO ''applicability test.'' The letter concluded that ''steam generating units'' include not only electric utility plants with boilers, but also plants with combined cycle gas turbines if the combined cycle gas turbine systems supply more than one-third of their potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Consequently, qualifying combined cycle gas turbines must also use the 2-in-5-years baseline method.

[20] Letter from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Patrick M. Raher, August 6, 2001.

Finally, today's rules provide the same method for EUSGUs that will exist for all other existing emissions units to project post-change emissions following a physical or operational change to a unit. In the 1996 proposal, we proposed a range of options for addressing the applicability of changes that are made to existing emissions units, including the option of extending the actual-to-future-actual test, then available only to utilities, to all source categories. While we have decided to leave the WEPCO rules intact in most respects, we believe that it is reasonable and appropriate to establish a consistent method for sources to use for projecting the post-change emissions that will result from a physical or operational change to an existing emissions unit. Therefore, under today's new rules, the current method of basing the projection on the 2 years following the change to an EUSGU is being replaced with the method available to all other existing units, under which you project a unit's post-change emissions as the maximum annual rate that the unit will emit in any one of the 5 years following resumption of regular operations.

F. The ''Hybrid'' Applicability Test for Projects Affecting Multiple Types of Emissions Units

1. When Does the Hybrid Applicability Test Apply to You?

The hybrid applicability test applies if you plan a project (or series of related projects) that will affect emissions units of two or more of the following types.

- Existing emissions units
- New emissions units
- Clean Units

2. How Do I Determine Whether My Project Will Result in a Significant Emissions Increase Under the Hybrid Test?

For the first two types of emissions units listed above that are affected by the project, calculate the emissions increase as we have discussed previously in this preamble. That is, use the actual-to-projected-actual applicability test for existing units and the actual-to-potential test for new emissions units.

Clean Units are discussed fully in section V of this preamble. If a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, no emissions increase shall be deemed to occur at that Clean Unit. If a given project would cause the emissions unit to lose its Clean Unit status, then the increase in emissions should be calculated as if the emissions unit is not a Clean Unit.

After you calculate the emissions increase for each relevant unit, total the increases across all the emissions units of all types. If this total emissions increase equals or exceeds the level defined as significant for the regulated NSR pollutant in question, the project will result in a significant emissions increase for that pollutant. You'll find the regulatory language for determining whether a project will result in a significant emissions increase at §§ 51.165(a)(2)(vii)(D), 51.166(a)(7)(vi)(*d*), and 52.21(a)(2)(vi)(*d*).

In section II.C.8 of this preamble, we indicate that the baseline actual emissions for all units that are not EUSGUs that are changed by a project must be calculated based on the same consecutive 24-month period within the previous 10 years. The same principle applies under the hybrid test, but it can be slightly more complicated if both EUSGUs and non-EUSGUs are involved. In this case, you must use the same baseline period for all emissions units affected by the project. This baseline period must be selected so as to meet the requirements for both EUSGUs and non-EUSGUs. Thus, you must select a 2-year period out of the previous 5 years for your baseline period, as required for EUSGUs (and within the requirements for non-EUSGUs). If you wish to use another period that you believe is more representative (as allowed for EUSGUs), the entire period must fall within the previous 10 years (as required for non-EUSGUs).

3. How Do I Determine the Net Emissions Increase From My Project Under the Hybrid Test?

If you conclude that a significant emissions increase will result from the proposed project, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to ''net out'' of review, that is, show that the net emissions increase at the major stationary source will not be significant. The netting analysis is carried out under the hybrid test just as it is under the other applicability tests. Refer to section II.D.7 of this preamble for a discussion of netting methodology.

G. Legal Basis for Today's Action

The Act defines modification for the purposes of PSD and nonattainment NSR through cross-reference to the NSPS definition of ''modification.'' The NSPS definition states that a modification ''means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' CAA section 111(a)(4), 42 U.S.C. 7411(a)(4). The Act is silent, however, on the issue of how one is to determine whether a physical or operational change increases the amount of any air pollutant emitted by the source.

Accordingly, EPA is exercising its discretion in interpreting and providing clarity to this issue. We believe that the rules set forth today are ''a permissible construction of the statute.'' *Chevron U.S.A., Inc.* v. *NRDC,* 467 U.S. 843–4 (1984). The reviewing court should defer to it. *Id.* at 837.

In the NSPS program, we determine whether there has been an ''increase in any air pollutant emitted'' by the source by comparing its maximum hourly achievable emissions before and after the change. EPA and the courts have recognized, however, that the NSR programs and the NSPS programs have different goals,[21] and thus, we have utilized different emissions tests in the NSR programs. Prior to today, the regulations applied an actual-to-future-actual applicability test for EUSGUs and an actual-to-potential applicability test for all other emissions units. Today, we are establishing a new applicability test for calculating emissions increases for ''Clean Units'' and an actual-to-projected-actual applicability test for all other emissions units. We believe that establishing an actual-to-projected-actual applicability test for all emissions units is a reasonable interpretation of the phrase ''increase of any pollutant emitted.''[22]

H. Response to Comments and Rationale for Today's Actions

We received numerous comments on our proposed rule regarding the calculation of the baseline actual emissions and the actual-to-future-actual test. Some of the significant comments and our responses to them are provided below. A complete set of comments and our responses can be found in the Technical Support Document located in the docket for this rulemaking.

1. Why Are We Extending the Look Back Period for Determining the Baseline Actual Emissions to 10 Years?

Most commenters generally support our proposal to allow owners and operators to use a 10-year look back period to determine the baseline actual emissions for modifications at any existing emissions unit. Commenters have various reasons for supporting or opposing the proposed approach. Many supporters agree that extending the baseline look back period to 10 years would simplify current regulations and provide certainty to sources who otherwise would have to demonstrate to the reviewing authority that a period other than the 2 years immediately preceding the proposed change was more representative of normal source operation. Some commenters support the proposal because it would prevent the perceived confiscation of underused capacity at sources that have had low utilization rates for an extended period. These commenters agree that a 10-year look back period is more likely to afford a source a baseline actual emissions calculation that best reflects representative source operating conditions and would also account for fluctuations in the business cycle.

Some commenters criticize the proposed 10-year look back period as being too long. These commenters recommend either a 5-year or 2-year look back period. One of these commenters states that the 10-year look back creates the opportunity for a source to increase production to the 10-year maximum, and prevents the State or local air regulators from addressing the increase in emissions. Thus, the commenter believes that sources would be allowed to use historic emissions levels that are higher than current levels to establish the baseline actual emissions. Some commenters add that the proposed change would not reduce program complexity.

Some commenters believe that instead of extending the period for establishing baseline actual emissions, the test for establishing modifications should be changed. According to the commenters, the problem is not that the current system does not go back far enough to set a fair actual emissions baseline, but that the methodology does not account for the fact that most emissions units are operating at an activity level much lower than the allowed activity level. The commenters believe that many of the real problems associated with the current major modification applicability test would be eliminated if the procedure was modified in an equitable manner.

A commenter also adds that EPA may also want to include provisions that prevent a source from applying the new definition of actual emissions in a way that would retroactively enable the source to reverse a previous major modification determination and to eliminate any emissions reduction previously required for that major modification.

We continue to believe that it is reasonable and appropriate to adopt the new method for establishing a modified unit's baseline actual emissions. It is important to understand the difference between the purpose of the new procedure, which uses the 10-year look back, and the existing procedure under the pre-existing definition of ''actual emissions'' at § 52.21(b)(21(ii), which generally requires the use of an average annual emissions rate based on the 2-year period immediately preceding a particular date. The latter procedure is designed to estimate a source's actual emissions at a particular time and continues to be appropriate for such things as estimating a source's impact on air quality for PSD increment consumption.

On the other hand, the new baseline procedure is specifically designed to allow a source to consider a full business cycle in determining whether there will be an emissions increase from a physical or operational change. Generally, a source's operations over a business cycle cover a range of operating (and emissions) levels—not simply a single level of utilization. The new procedure recognizes that market fluctuations are a normal occurrence in most industries, and that a source's operating level (and emissions) does not remain constant throughout a source's business cycle. The use of a 24-month period within the past 10 years to establish an average annual rate is intended to adjust for unusually high short-term peaks in utilization.

Consequently, the new procedure ensures that a source seeking to make changes at its facility at a time when utilization may not be at its highest can use a normal business cycle baseline by allowing the source to identify capacity actually used in order to determine an average annual emissions rate from which to calculate any projected actual emissions resulting from the change.

With respect to the commenters' general concerns that a 10-year look back period is too long, we sought to better understand what time period best represents an industry's normal business cycle. Therefore, we contracted for a study of several industries in 1997.[23] This study found that, for the

[21] See, for example, WEPCO Rule, 57 FR 32316 (''fundamental distinctions between the technology-based provisions of NSPS and the air quality-based provisions of NSR''). See also *ASARCO Inc.* v. *EPA,* 578 F.2d 319 (D.C. Cir. 1978).

[22] The explanation of the applicability test for ''Clean Units'' is discussed in section V.

[23] ''Business Cycles in Major Emitting Source Industries.'' Eastern Research Group; September 25, 1997. This study examined the business fluctuations for nine source categories described as CAA major emitting sources. Industry business cycles were examined using industry output data

Continued

industries analyzed, business cycles differ markedly by industry, and may vary greatly both in duration and intensity even within a particular industry. Nevertheless, we concluded from the study that 10 years of data is reasonable to capture an entire industry cycle. Comments from various industries support a conclusion that a 10-year look back period is a fair and representative time frame for encompassing a source's normal business cycle.

We believe that the use of a 10-year look back period will help provide certainty to the process and eliminate the ambiguity and confusion that occurred when an applicant and the reviewing authority disagreed on what time frame provides the period most representative of normal source operation. The new requirements also provide certainty to the look back period, since there is no opportunity to select another period of time outside this 10-year period. (See additional discussion in section II.E.2.) In addition, we have placed certain restrictions on when the full 10-year look back period may be used. (*See* section II.E.3.)

With regard to the concern that industry may try to apply the new requirements retroactively to undo current restrictions on existing sources, we want to reiterate that the new procedures do not apply retroactively to existing NSR permits or changes that sources have made in the past. Prior applicability determinations on major modifications and the control requirements that currently apply to sources remain valid and enforceable and have to be adjusted for in the calculation of baseline actual emissions. However, as part of the transition process for implementing the new provisions, we do intend to allow permit applicants to withdraw any permit applications submitted for review under the part 52 Federal PSD permit program so that they may re-evaluate their projects in light of the new requirements. States may allow for the same type of transition process under their own NSR programs.

Finally, we considered whether we should change the length of the look back period for EUSGUs for establishing the actual emissions baseline period to be consistent with the 10-year look back period we are adopting for other existing emissions units. The data we collected to support the 1992 rule changes show that allowing EUSGUs to use any 2-year period out of the preceding 5 years is a sufficient period of time to capture normal business cycles at an EUSGU. We do not believe that any information received during the public comment period for this final rule adequately supports a different conclusion. Thus, we have decided to retain the 2-in-5-years baseline period for EUSGUs. However, for consistency with the baseline period for other existing emissions units, we have specified that the 2-year period is a consecutive 24-month period.

2. Why Do the New Requirements Not Provide Discretion for the Reviewing Authority To Consider Another Time Period More Representative of Normal Operation for Non-EUSGUs?

Several commenters oppose our proposed elimination of the reviewing authority's discretion to allow a different representative period (outside of the 10-year period), because they argue certain sources (for example, emissions units placed in cold reserve due to reduced demand) require this flexibility. Some commenters say the discretion should be given to the reviewing authority, while other commenters wanted the discretion given directly to source owners and operators. Instead of the discretion to use an alternate period, one commenter prefers that all sources should be required to show that they have selected a representative period that precedes the most recent 2-year period.

We believe that use of a fixed 10-year look back period provides the desired clarity and certainty to the process of selecting an appropriate utilization/emissions level that is representative of a source's normal operation. A bounded 10-year look back provides certainty to the regulated community that may be undermined by an option to allow an unbounded alternative period as well.

3. Why Are We Placing Restrictions on the Use of a 10-Year Look Back for Setting the Baseline Actual Emissions?

Numerous commenters responded to our concern that many sources might lack accurate records for the full 10-year look back period, and to our request for comments on the need to condition the full use of the 10-year period upon the accuracy and completeness of available data, as well as the need to establish specific criteria for accuracy, completeness, and recordkeeping when using older data. A number of commenters generally support limiting full use of the 10-year look back period to situations in which adequate emissions and/or capacity utilization data are available. Some commenters also recommend that EPA issue minimum criteria to reduce the number of case-by-case determinations and help reviewing authorities avoid debates with sources on what constitutes sufficient data.

On the other hand, one commenter recommends that we not adopt a variable look back period based on the quality of the older data because it would ''add considerable uncertainty and protracted debate to the process. . . .'' If, however, we choose to limit the look back period based on the quality of older data, then this commenter and several others prefer provisions allowing for case-by-case decisions by State or local reviewing authorities over specific criteria established by EPA.

Today's amendments condition the full use of the new 10-year look back period on the accuracy and completeness of your records of emissions and capacity utilization, with respect to the 24-month period you select, for any emissions unit that undergoes a physical or operational change. *See,* for example, new § 52.21(b)(48)(*f*). As with all emissions calculations, accuracy and completeness are central elements for applicability determinations. In many cases, sources presently maintain accurate records on emissions and operations for only 3 to 5 years. Thus, we think it is appropriate to limit use of the full 10-year look back period when you do not have adequate data for the time period you wish to select. However, this limitation should be alleviated over time as sources begin to maintain records for longer periods to accommodate the 10-year look back opportunity.

We also agree that adequacy of any given data should be left to the case-by-case judgment of individual reviewing authorities. The type of data necessary to determine emissions will vary drastically from source category to source category and from process to process within a source category. At this time, we are not able to issue generic criteria that would apply to all types of industries.

We are further restricting your use of the 10-year look back for emissions units that are located in nonattainment areas and OTRs. In such cases, you are precluded from using any portion of the 10-year look back that precedes November 15, 1990—the date of the 1990 CAA Amendments—to establish baseline actual emissions for those units. This limit on the use of the 10-year look back is consistent the intent of the 1996 NPRM, which was originally proposed to apply to the use of the 10-year look back for any modification of an existing facility in a nonattainment

for the years 1982 to 1994 inclusive, based on the Office of Management and Budget's SIC codes for individual industries (OMB, 1987).

area or OTR. See 61 FR 38259 (July 23, 1996). However, because we are now beyond the point where the November 15, 1990 limit is relevant to modifications, we are only applying this limitation in the netting context with respect to emissions units changed within the contemporaneous period.

4. Why Were Changes Made to the Proposed Approach for Establishing Baseline Actual Emissions Using a 10-Year Look Back?

Commenters raise specific questions about how to use the 10-year look back to calculate an emissions unit's baseline actual emissions. Several commenters are concerned about how the utilization rate would be considered in the calculation. For example, some commenters support the proposal to allow sources to use their highest capacity achieved during any consecutive 12 months, because it provides improved flexibility in establishing a capacity level that is representative of normal operations. However, other commenters object to using the 12 months with the highest utilization. These commenters argue that the use of production rates can be unworkable because there is not always a clear relationship between production rate and emissions. In addition, reliable records may not be available to determine the highest production rates. As an alternative, commenters suggest using emissions from any 12-month period in the preceding 10 years, adjusted to reflect current rules, or allowing the source to use any 12-month period of its choice.

A related issue raised by commenters is whether to require any current Federal, State, or voluntary limit to be included in the establishment of the baseline actual emissions. Some commenters say these provisions would penalize sources that complied with other regulatory requirements or chose to implement pollution prevention programs. Commenters are particularly concerned that sources be given credit for voluntary reductions. However, other commenters support including all of these factors in the baseline to better represent actual emissions and avoid inconsistencies between emissions units that have permits and those that do not. Commenters also raise specific questions about how the calculation would include the effect of other emission limitations.

As described earlier, we have decided to require the use of a consecutive 24-month period within the 10-year look back instead of the proposed 12-month period to calculate the baseline actual emissions for any emissions unit that undergoes a physical or operational change, or is affected by such change. The longer 24-month period allows you to reference levels of utilization achieved in the past, but also eliminates the potential problem associated with short-term peaks that do not truly represent the unit's normal operation. In this respect, the use of a 24-month period is consistent with the pre-existing approach for calculating actual emissions.

With respect to commenters' concerns about being required to use the period of highest utilization, our reference in the proposal preamble to selecting the period of highest utilization was based on our general assumption that the period of maximum utilization also represents the period of highest pollution levels for the unit of concern. However, you are not required to select the period of highest utilization. The choice of which consecutive 24-month period within the 10-year window to use is up to you. The two restrictions on the selection of the appropriate consecutive 24-month period, as described earlier, are the availability of adequate and complete source records for the unit of concern and the limit on using dates earlier than November 15, 1990 for contemporaneous emissions changes in nonattainment areas and OTRs.

We agree with the concerns expressed by some commenters that the baseline actual emissions calculated from the consecutive 24-month period selected could yield a higher pollution level than a unit is currently allowed to emit. We do not believe that we should allow a source to take credit for baseline actual emissions that exceed the current, legally allowable emissions rate. Consequently, the new requirements require you to determine whether any legally enforceable limitations currently exist that would prevent the affected unit from emitting a pollutant at the levels calculated from the 24-month baseline period. The approach that we have adopted allows you to reference plant capacity that has actually been used, but not pollution levels that are not legally allowed at the time the modification is to occur. You will be required to make adjustments for voluntary reductions that you may have taken only to the extent that the reductions resulted from conditions that are legally enforceable limitations.

5. How Does the Change in the Baseline Period Affect Related Requirements Regarding Protection of Air Quality?

a. How Does the Extended Baseline Period Conform With the Special Modification Provisions Under Sections 182(c) and (e) of the Act?

Most commenters feel the proposed extension of the look back period fits within the design and intent of the special modification procedures set forth in sections 182(c) and (e) of the Act, applicable in serious, severe, and extreme ozone nonattainment areas. However, one commenter representing State and local air pollution control agencies considers the new requirements to be in significant conflict with the special modification procedures contained in those sections of the Act. The commenter indicates that this conflict could be resolved by deferring to relevant requirements for modifications in serious, severe, and extreme areas. The commenter adds that while NSR programs are tools to attain and maintain compliance with the NAAQS, they should not be available to undermine specific statutory and SIP requirements designed to resolve nonattainment problems.

We disagree with the commenter's concern that the use of a 10-year look back period to implement sections 182(c) and (e) of the Act for purposes of establishing a modified unit's baseline emissions will undermine any statutory or SIP requirements designed to address nonattainment problems. The two sections establish special procedures for determining whether a proposed modification of a major stationary source of ozone in a serious, severe, or extreme ozone nonattainment area will be subject to major NSR under part D of the Act. The Act is silent on the issue of how one is to determine whether a physical or operational change increases the amount of a pollutant for a changed emissions unit. We believe, therefore, that we have the authority to establish a regulatory procedure for making the required determinations concerning emissions increases resulting from physical or operational changes.

In light of the fact that the 10-year look back period may be used for emissions units (other than EUSGUs) that are involved in contemporaneous emissions changes (for netting purposes), it should be noted that the new requirements prohibit the use of the look back period earlier than November 15, 1990. Consequently, for emissions units whose contemporaneous emissions changes occurred before November 15, 2000, the consecutive 24-month period selected for calculating the baseline actual emissions relevant to the contemporaneous emissions change cannot include a date prior to November 15, 1990. It should be pointed out, however, that for modifications involving emissions of volatile organic compounds (VOC) in areas classified as ''extreme,'' the statutory language is clear that the increase in emissions resulting from the change is not required to be a significant increase, but rather that ''any increase'' that is projected using the new actual-to-projected-actual applicability test will trigger the applicable NSR requirements.

b. Will the Longer Look Back Period Related to the Baseline Actual Emissions Protect Short-term Increments and NAAQS?

Some commenters express concerns that the opportunity to take credit for older baseline actual emissions would result in adverse environmental consequences. One commenter specifically indicates that the proposed baseline actual emissions determination process, involving a 10-year look back, would allow significant increases in emissions to escape the ambient impact review requirements otherwise required by NSR.

Today's new rule modifies the way your NSR applicability determinations are made for changes made to existing emissions units. The new rule does not affect the way in which a source's ambient air quality impacts are evaluated. Compliance with the NAAQS is accomplished with air quality dispersion models using maximum allowable emission limitations (or federally enforceable permit limits) combined with operating factors, which consider either design capacity or actual operating factors averaged over the most recent 2 years of operation, from all modeled sources.[24] In addition, any increase in actual emissions, based on the existing definition of ''actual emissions,'' consumes PSD increment whether it occurs through normal source operation or as a result of a physical or operational change. As mentioned earlier, the existing definition of ''actual emissions'' continues to apply with regard to all NSR requirements other than the new source applicability tests. *See,* for example, new § 52.21(b)(21)(i). Thus, we do not believe there is a basis for concluding that the use of a longer look back period for determining a modified emissions unit's baseline actual emissions (for purposes of determining whether a physical or operational change will result in a significant emissions increase) will cause any adverse environmental impacts.

6. Why Was the Contemporaneous Period for Netting Not Also Changed to a 10-Year Look Back Period?

In the 1996 NPRM, we indicated that we were not proposing to extend the 5-year contemporaneous period along with the proposed 10-year look back period associated with the establishment of baseline actual emissions. *See* 61 FR 38259 (July 23, 1996). We did, however, solicit comments on the effect of the differing look back periods and any reasons why these periods should be the same. Commenters responded in a variety of ways to our request, with no clear consensus as to whether it would be appropriate to establish a uniform look back period. One commenter supports the 10-year contemporaneous period for reasons of consistency. Other commenters believe that it was reasonable to use two different time frames. Some commenters support retaining the 5-year contemporaneous period because changing it could have adverse effects on existing permit determinations. Several commenters support the selection of a different contemporaneous time frame than the existing 5-year period, but they differ in their recommendations for changing it. One suggests giving the source the option of choosing either a 10-year or 5-year contemporaneous period. Another commenter believes that a 1-year period would reduce confusion. Finally, another commenter proposes a 5-year contemporaneous period that would not mandate that 5 consecutive years be considered.

We do not believe that there is a compelling reason to change the existing 5-year contemporaneous period. The look back periods serve different purposes and need not be the same in order to effectively implement the NSR program objectives. States retain the flexibility in defining a different contemporaneous period under SIP-approved NSR programs, and may use that flexibility to adjust the contemporaneous period if they believe that a different period is more appropriate for their purposes under the new applicability requirements. *See,* for example, § 51.166(b)(3)(ii). Therefore, under today's new requirements, we have not changed the 5-year contemporaneous period under the Federal PSD program. It should be noted that for purposes of determining the baseline actual emissions of a contemporaneous change in emissions from an emissions unit that was an existing unit at the time of the contemporaneous change, the new requirements authorize a source to use the 10-year look back period.

7. Why Was the Demand Growth Exclusion Retained?

When we proposed to expand the scope of the WEPCO rulemaking to cover modifications at any existing emissions unit, we solicited comment on whether the demand growth exclusion (currently available only to EUSGUs) should also be available to all source categories. In 1998, we noted that there were problems that could arise with the demand growth exclusion. 63 FR 39860–39861 (July 24, 1998). Accordingly, we solicited comment on this new position.

Several regulatory agency and environmental commenters support the total elimination of the demand growth exclusion. These commenters maintain that a facility's post-change emissions increases due to demand growth could not be disassociated from those that resulted directly from the physical or operational change. These commenters believe the demand growth exclusion would be difficult to enforce. The demand growth exclusion would, they claim, also be burdensome because it would require projections, estimates, and post-modification evaluations of increased emissions to determine whether the increases were the result of increased demand.

On the other hand, numerous industry commenters oppose eliminating the demand growth provisions, stating that market factors do independently cause emissions increases absent physical and operational changes. These commenters maintain that when projected increased capacity utilization is in response to an independent factor, such as demand growth, the increased utilization cannot be said to result from the change and therefore may rightfully be excluded from the projection of the emissions unit's future-actual emissions. They further argue that such increases should not be included in post-change emissions even in the absence of a demand growth exclusion, as the increases would not be the result of the physical or operational changes that were made. Consequently, these commenters state that the proposed demand growth exclusion simply makes that principle explicit and eliminates confusion as to how emissions should

[24] Guidance for modeling NAAQS compliance under the PSD program is set forth in EPA's Guideline on Air Quality Models contained in appendix W of 40 CFR part 51. This guidance is incorporated by reference both in the Federal PSD regulations and in the minimum requirements for SIPs under the part 51 PSD regulations.

be calculated. The same commenters who support retaining demand growth provisions for utilities also believe these provisions should be extended to non-utilities.

Under today's new requirements, you will be allowed to apply the causation provision as originally contained in the WEPCO amendments. Both the statute and implementing regulations indicate that there should be a causal link between the proposed change and any post-change increase in emissions, that is, ''* * * any physical change or change in the method of operation *that would result in* a significant net emissions increase * * *'' [emphasis added]. See, for example, existing § 52.21(b)(2)(i). Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as growth in market demand, you may subtract the emissions increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit. See for example, new § 52.21(b)(41)(ii)(*c*).

On the other hand, demand growth can only be excluded to the extent that the physical or operational change is not related to the emissions increase. Thus, even if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the project, and cannot be subtracted from the projection of projected actual emissions.

8. Should Increases in Plant Utilization Be Reviewed as Potential Major Modifications?

Many commenters argue that emissions increases resulting from increased utilization should not be subjected to review as major modifications. They insist that EPA's policy and rules have always allowed increases in capacity utilization without triggering a modification, and not allowing utilization increases will limit new capacity to new emissions units instead of promoting increased efficiency at existing emissions units. One commenter argues that these sorts of changes do not require any sort of applicability determination and that Congress never anticipated that the NSR program would hamper a source's ability to increase utilization up to the original design capacity.

We believe that an increase in utilization should not trigger the major NSR requirements unless it is related to a physical or operational change. As explained earlier, the CAA only applies the major NSR requirements to emissions increases that are the result of a physical or operational change. Thus, we do not believe that the major NSR requirements should apply to a utilization increase unless the increase is related to the modification. Under today's final rules, you may exclude emissions related to an increase in utilization if you were able to accommodate the increase in utilization during the 24-month period you select to establish your baseline actual emissions and the increased utilization is not related to the change.

9. Why Must You Track Physical or Operational Changes That Increase a Unit's Design Capacity or Potential To Emit Post-Change Actual Emissions for a Longer Period of Time?

We raised this issue in the 1998 NOA. Several commenters support applying what we then termed the ''actual-to-enforceable-future-actual'' test to increases in design capacity or PTE because it would be inappropriate to automatically assume that such increases will affect normal operations, which would require the actual-to-potential test. They say that these types of modifications are common and do not generally increase emissions because they improve efficiency and add control devices.

One commenter explains that it is not uncommon for an emissions unit's capacity to be increased so as to speed up normal operations without increasing production, and that projected actual emissions could easily be calculated on the basis of past operating experience. On the other hand, another commenter indicates that it is very expensive to increase design capacity. Therefore, it can be assumed that a company would use the additional capacity as soon as it becomes available.

Several regulatory agency commenters support the use of the actual-to-potential test for modifications that increase design capacity or PTE. One of these commenters stated that such modifications would alter an emissions unit's normal operation and make previous actual emissions ''unreliable and irrelevant.''

We do not believe that every modification that includes added capacity or an increase in the PTE is intended for full use of that new capacity or PTE. Such actions could well be intended to enhance current operations without resulting in increased production or operation. Therefore, under today's new requirements, you are not required to count the emissions increase that would result from full use of new capacity or PTE if you conclude that: (1) Such capacity or PTE will not be fully utilized, and (2) the emissions increase resulting from that portion of the capacity that will be used will not result in a significant emissions increase from the modification or a significant net emissions increase at the source. The new requirements include a provision that requires you to monitor the emissions from the project for 10 years following the resumption of regular operation of the emissions units modified. The 10-year period reflects our determination that this time frame best captures the normal business cycle for industry in general. Thus, in situations where your proposed project will in fact add new capacity or PTE to an existing emissions unit, yet you determine that the objective of the physical or operational change is not to use the increased capacity, your calculation of representative projected actual emissions may reflect this. However, you must maintain adequate information for 10 years following the completion of the project to track the actual annual emissions from the units associated with the project. This represents a special condition that supersedes the normal 5-year period for the recordkeeping requirements being adopted today. During the 10-year period, you must report to your reviewing authority within 60 days after any year if the annual emissions, in tpy, from the project exceed the baseline actual emissions by a significant amount for the regulated NSR pollutant and if such emissions differ from the preconstruction projection.

10. Does the Actual-To-Projected-Actual Applicability Test Apply to Netting?

We did not specifically request comment on this issue in the 1996 proposal. Nonetheless, we received several comments that assert that use of different methods to compute an emissions increase and determine a net emissions increase would result in ''absurd results'' and require two separate accounting records. Other commenters oppose using the actual-to-future-actual test for netting. One commenter says that the sole purpose of the actual-to-future-actual test was to determine if an emissions increase will occur. One commenter says we should go further and revise the definition of ''contemporaneous'' to limit it to project activities (vs. plantwide) and reduce credits for shutdowns and curtailments.

As stated previously, we did not specifically request comment on this issue and we are not promulgating amendments to the netting regulations, on this point, at this time.

11. Should We Impose an Enforceable Projected Actual Emissions Level?

Some commenters on our 1996 proposal support the establishment of an enforceable limitation on the modified source's projected future emissions level. Other commenters support our specific proposal in the 1998 NOA to use the projected actual emissions as a temporary cap for the emissions units involved in the project, that is, an enforceable 10-year emissions level.

On the other hand, many other commenters oppose the concept, citing various reasons for their opposition. These included concerns that it would become a *de facto* baseline for any additional permitting and create additional enforcement liability, usurp State prerogatives, be inconsistent with the CAA, and require enforceable restrictions for too long. A few State and local air reviewing agencies indicate that they do not have the resources to adequately administer a program that would require permits to be issued for every physical or operational change at a major stationary source.

Today's new requirements follow the 1996 proposal. You will not be required to make the projected actual emissions projection through a permitting action. After considering the comments received, we are concerned that such a requirement may place an unmanageable resource burden on reviewing authorities. We also believe that it is not necessary to make your future projections enforceable in order to adequately enforce the major NSR requirements. The Act provides ample authority to enforce the major NSR requirements if your physical or operational change results in a significant net emissions increase at your major stationary source.

12. Why Are Modified Sources That Are Not Considered Major Modifications Not Required To Submit Annual Reports of Actual Emissions Under the New Requirements?

Several commenters support our proposal to require sources to track post-change emissions for a 5-year period so that there is a factual finding as to whether emissions from the modified units actually increased. These commenters believe that the requirement to track emissions is a needed safeguard and that it should not be too difficult to track various operating parameters. They add that non-utilities should be able to track emissions as well as utilities. Finally, commenters who oppose the proposed 10-year enforceable limit support retaining the 5-year tracking period in its place.

Many other commenters object to the burden that tracking would impose in the absence of any additional environmental benefit. Some commenters suggest ways to reduce the burden, such as not requiring sources to report emissions unless there is a problem or reducing the tracking period to 2 or 3 years. Another industry commenter suggests that we require an up-front notification to the reviewing authority whenever the actual-to-future-actual applicability test is used.

We agree with those commenters who recommend that you should be required to track emissions for a period of time following a modification. Thus, we have retained our proposed requirement to maintain annual emissions information for a period of 5 years following resumption of regular operations after the change. As discussed previously, we expanded this requirement to 10 years for changes that increase an emissions unit's capacity or its potential to emit a regulated NSR pollutant. However, although we proposed a requirement for annual emissions reporting, we have concluded that the combination of the recordkeeping requirements of this rule, along with a requirement to report to the reviewing authority any annual emissions that exceed your baseline actual emissions by a significant amount for the regulated NSR pollutant and differ from your preconstruction projection, is an equally effective way to ensure that a reviewing authority can receive the information necessary to enforce the major NSR requirements. Moreover, your reviewing authority has the authority to request emissions information from you at any time to determine the status of your post-change emissions.

In response to the concern that these requirements might impose unnecessary burdens, we have also included further limits. First, you are only required to keep records if you elect to use the actual-to-projected-actual applicability test to calculate your emissions increase from the project. Second, you are only required to keep the records if there is a reasonable possibility that your project might result in a significant emissions increase. Finally, you only need keep those records for projects that are not major modifications.

We also considered requiring you to submit an up-front notification to your reviewing authority, but concluded that this would result in an unnecessary paperwork burden. (EUSGUs, however, will be required to submit a copy of their projections to reviewing authorities before beginning actual construction.) We anticipate that a large majority of the projects that are not major modifications may nonetheless be required to undergo a permit action through States' minor NSR permit programs. In such cases, the minor NSR permitting procedures could provide an opportunity to ensure that your reviewing authority agrees with your emission projections. Requiring a separate notification would not provide the reviewing authority with any additional information in such circumstances. Accordingly, we believe today's requirements provide reviewing agencies with the ability to obtain all the information necessary to ensure compliance.

13. Why Are We Promulgating Different Reporting Requirements for Existing Emissions Units Than for EUSGUs?

Today we are finalizing slightly different requirements for EUSGUs than other industries. In 2000, boilers and turbines with greater than 25 MWe or 250 mmBTU/hr of generating capacity represented 76 percent of this nation's emissions of nitrogen oxides (NO_X) and 85 percent of this nation's emissions of SO_2 from stationary sources.[25]

In view of the disproportionate amount of emissions generated by EUSGUs compared to other industry sectors, we believe that it is appropriate for reviewing authorities to have information on construction and modification activities at EUSGUs readily available. Accordingly, we are requiring EUSGUs to provide a copy of their emissions projection to the reviewing authority before beginning actual construction of a project. We are also requiring them to report their post-change annual emissions for every year they are required to generate them. This approach also makes sense because it focuses the limited resources of both sources and agencies on the sources that matter most.

III. CMA Exhibit B

In addition to the proposed changes based on the 1992 WEPCO amendments (*see* section II of this preamble), the 1996 proposal package included alternative regulatory language that would enable you to determine whether

[25] Information supporting these values can be found in the docket for today's rulemaking.

your facility has undertaken a modification based on the facility's pre-change and post-change potential emissions instead of its actual emissions. This action was part of the settlement of a challenge to our 1980 NSR regulations by CMA and other industry petitioners. The exact language we proposed was set forth in Exhibit B to the Settlement Agreement, which is contained in the docket for this rulemaking.

Under this method, sources may calculate emissions increases and decreases based on the actual emissions method or the unit's pre-change and post-change potential emissions, measured in terms of hourly emissions (that is, pounds of pollutant per hour). Sources could use this potential-to-potential test for NSR applicability, as well as for calculating offsets, netting credits, and other ERCs.

We proposed to make several changes to the NSR regulations. First, we proposed to add the following exclusion to the definition of ''major modification'':

> A major modification shall be deemed not to occur if one of the following occurs: (a) there is no significant net increase in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour); or (b) there is no significant net increase in the source's actual emissions.

Second, we proposed to delete all references to ''actual emissions'' in the definition of ''net emissions increase'' and added language indicating that all references to ''increase in emissions'' and ''decreases in emissions'' in the definition of ''net emissions increases'' ''shall refer to changes in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour) or in its actual emissions.'' Third, we proposed to modify the applicability baseline by eliminating the reference to the 2-year baseline period and to a method for determining actual emissions during the representative period. Finally, we proposed to provide express authorization for sources to use potential emissions in calculating offsets and in creating ERCs.

We also indicated in the preamble for the 1996 proposed rulemaking that if we promulgated the Exhibit B settlement as a final rule, the Exhibit B rules would need to be updated to reflect other rule changes since 1980, as well as relevant provisions of the 1990 Amendments.

Before proposing the Exhibit B language, we did a preliminary analysis of the impact on the NSR program of the Exhibit B changes. These changes would provide maximum flexibility to existing facilities with respect to determining if a significant net emissions increase would result from a physical or operational change. However, we also expressed concern about the environmental consequences associated with the Exhibit B provisions. For one, you could modernize your aging facilities (restoring lost efficiency and reliability while lowering operating costs) without undergoing preconstruction review, while increasing annual pollution levels as long as hourly potential emissions did not change. Also, Exhibit B would allow your facilities to generate netting credits and ERCs for offsets based on potential hourly emissions, even if never actually emitted. This could sanction greater actual emissions increases to the environment, often from older facilities, without any preconstruction review. In addition, actual emissions increases resulting from unreviewed projects could go largely undocumented until a PSD review is performed by a new or modified facility that ultimately must undergo review. By that time, however, a violation of an increment could have unknowingly occurred. We were also concerned that Exhibit B would ultimately stymie major new source growth by allowing unreviewed increases of emissions from modifications of existing sources to consume all available increment in PSD areas.

In our analysis supporting the 1996 proposal, we were unable to reach any conclusions as to the magnitude of any environmental impacts beyond noting that the effects would vary from State to State depending on how much cumulative difference exists between the unused potential emissions and actual emissions in a given inventory of sources and on the extent to which any unused potential emissions have been used in attainment demonstrations. However, our analysis did show that typical source operation frequently does result in actual emissions that are below allowable emission levels.

We received many comments in response to the 1996 proposal regarding CMA Exhibit B. Some commenters believe the potential-to-potential test appropriately focuses on the significant emissions changes that could produce an adverse environmental impact. Several other commenters believe that a potential-to-potential test would be environmentally detrimental. These commenters believe that CMA Exhibit B represents a substantial weakening of the PSD program with large increases in actual emissions, which in itself could lead to a significant deterioration of air quality. They also express concerns regarding the creation of paper credits and other impacts on the broader air quality planning process. One commenter states that the potential-to-potential test would conflict with SIPs that are based on actual emissions, threaten a State's efforts to make reasonable further progress (RFP) demonstrations, and interfere with emission credits relied on by SIPs. These commenters also cite the following concerns.

- The potential-to-potential test would allow sources to escape the major modification provisions and could virtually eliminate NSR in most modification cases.
- Once a facility has proceeded without NSR based on actual emissions, it would be difficult to take an enforcement action years later that would successfully require that facility to retrofit LAER and obtain offsets retrospectively.

We agree that a potential-to-potential test for major NSR applicability could lead to unreviewed increases in emissions that would be detrimental to air quality and could make it difficult to implement the statutory requirements for state-of-the-art controls.

After consideration, we believe some of the comments in support of Exhibit B have merit. As noted by commenters who supported the CMA Exhibit B proposal, a potential-to-potential test could simplify and improve the NSR process. According to commenters, the CMA Exhibit B approach would have the following benefits.

- Limit the scope of the program to encompass only those significant physical changes that Congress intended to cover
- Reduce unnecessary NSR costs and delays and improve compliance and enforcement
- Lower the cost of the NSR process by reducing the complexity of the NSR applicability determinations
- Facilitate applicability decisions at the plant level

The commenters also say that the CMA Exhibit B approach is more equitable than the existing actual-to-potential approach, which results in the capture of a source's unused capacity. These commenters prefer the potential-to-potential test because it would allow utilization increases. This provision is especially useful for sources in cyclical industries where using existing capacity is critical. Sources in sectors where utilization and demand are closely related would also benefit.

Our own concerns, coupled with the concerns expressed by some commenters, have caused us to reject the use of the Exhibit B regulatory changes for general purposes of determining whether a proposed physical or operational change would result in a major modification. For the reasons stated above, we do not believe that a potential-to-potential approach is acceptable for major NSR applicability as a general matter. However, we agree with the commenters in part—some of the benefits of a potential-to-potential approach are desirable. We believe that in more limited circumstances a ''potential-to-potential''-like approach would be acceptable. Therefore, we are promulgating two new applicability provisions that capture the benefits of a potential-to-potential approach but still have the necessary safeguards to ensure environmental protection—PALs, and the Clean Unit Test.

Today's rules provide for a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap, then you need not evaluate whether each change might be subject to the major NSR permitting when you make alterations to the facility or individual emissions units. The cumulative actual emissions become the *de facto* potential emissions for the plant, and you may emit up to the permitted level without going through major NSR, even if you are making changes to the facility. The PAL allows you to make changes quickly by allowing you to alter your facility without first going through major NSR review. It thus limits the number and complexity of NSR applicability determinations, and reduces unnecessary costs and delays. It also allows a plant manager to authorize changes, as long as the emissions remain under the permitted level, without first obtaining reviewing authority review. Furthermore, it provides an incentive to use state-of-the-art controls and install new, lower emitting equipment, which will allow sources to increase utilization. In return for the flexibility a PAL allows, you must monitor emissions from all of your emissions units under the PAL. Therefore, the PAL ensures good controls and protection of air quality. We believe there are other mechanisms for establishing PALs that would achieve beneficial results. For example, we believe PALs based on allowable emissions would produce flexibility and assure environmental protection, provided affected sources had adequate safeguards. Therefore, we intend in the near future to propose a rule that would adopt PALs based on allowable emissions.

Analogous to what the PAL does for facilities, the Clean Unit Test sets emission limitations or work practice requirements in conjunction with BACT, LAER, or Clean Unit determinations and identifies any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. The Clean Unit Test recognizes that if you go through major NSR review (including air quality review) and install BACT or LAER or comparable technology, then you may make any subsequent changes to the Clean Unit without triggering an additional major NSR review, as long as there is no need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT, LAER, or Clean Unit determination or to alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination. Therefore, for Clean Units, given that the permit is based on a determination that is protective of air quality, the new test would deem there is no emissions increase as a result of any physical change or change in the method of operation. With these provisions, sources will have improved certainty and flexibility, reduced burden, and opportunity for utilization increases without compromising air quality. Like the PAL, the Clean Unit includes necessary safeguards by requiring enforceable permit terms and conditions to ensure environmental protection.

IV. Plantwide Applicability Limitations

A. Introduction

Today we are adopting a final rule for a PAL option that is based on the baseline actual emissions[26] from major stationary sources. A PAL is an optional approach that will provide you, the owners or operators of major stationary sources, with the ability to manage facility-wide emissions without triggering major NSR. We believe the added flexibility of a PAL allows you to respond rapidly to market changes consistent with the goals of the NSR program.

The final rules we are adopting today also benefit the public and the environment. Reviewing authorities, usually States, can only establish a PAL by using a public process that affords citizens the opportunity to comment upon the proposed PAL. This process is designed to assure local communities that air emissions from your major stationary source will not exceed the facility-wide cap set forth in the permit unless you first meet the major NSR requirements. We believe that a PAL provides a more complete perspective to the public because in setting a PAL, your reviewing authority accounts for all current processes and all emissions units together and reflects the long-term maximum amount of emissions it would allow from your source. Moreover, to comply with a PAL you must meet monitoring requirements prescribed in the rules that ensure that both your reviewing authority and the public have sufficient information from which to determine plantwide compliance. Additionally, through the final PAL regulations, we are promoting voluntary improvements in pollution controls by creating an incentive for you to control existing and new emissions units to maintain a maximum amount of operational flexibility under the PAL. Most importantly, for pollutants subject to a PAL, we are prohibiting serial, small, unrelated emissions increases,[27] which otherwise can occur under our existing regulations.

If you choose to use it, we believe you will benefit from the PAL option because you will have increased operational flexibility and regulatory certainty, a simpler NSR applicability approach, and fewer administrative burdens. To comply with a PAL, you need to ensure that there are no emissions increases from your major stationary source, as measured against the PAL. For you to do that, there is no need for you to quantify

[26] In our 1996 proposal we used the term ''actual emissions,'' while today we are using the term ''baseline actual emissions.'' This change in terminology is consistent with the regulatory changes discussed in section II of today's preamble. Despite this change in terminology, there may be places in this section of the preamble where we still use the phrase ''actual emissions.'' In such cases we are either discussing PALs established under the old regulatory provisions, or summarizing and responding to comments received on the 1996 proposal.

[27] Under our current NSR program, you can make physical changes or changes in the method of operation without triggering major NSR applicability, provided the individual changes do not result in significant net emissions increases. We have interpreted this requirement to permit you to make unrelated changes that, standing alone, do not result in significant emissions increases and to allow such changes to occur without considering whether other contemporaneous emissions increases render the change significant. Over time you could undertake numerous unrelated projects without triggering major NSR, provided the individual projects did not increase emissions by a significant amount, thus allowing source-wide emissions to increase over time without requiring any emissions controls for these individual projects. For example, a large chemical plant that is located in an ozone attainment area adds a new product line in 2001 and properly avoids PSD (including the BACT requirement) by limiting the VOC emissions increase to 39 tpy. Later, in 2003 the plant adds a different product line and also properly avoids PSD by limiting VOC emissions from the new line to 39 tpy. For this example, two process lines at the same plant with total potential emissions (78 tpy) above the 40 tpy VOC significant level under PSD were properly permitted over a 3-year period without BACT applying to either new product line.

contemporaneous emissions increases and decreases for individual emissions units. Through the PAL we are allowing you to make timely changes to react to market demand and providing you additional certainty regarding the level of emissions at which your source will be required to undergo major NSR. The benefit to you is that you will not have to make numerous applicability decisions using different baselines. Also, in some situations where you would have been unable to ''net out'' a new project in the major NSR program, under a PAL you can begin construction on your new project without obtaining a major NSR permit, which can take from a few months up to 2 years. In addition, because you may make emissions reductions at emissions units under the PAL to create room for growth at other units, through the PAL we are providing a strong incentive for you to employ innovative control technologies and pollution prevention measures, to create voluntary emissions reductions to facilitate economic expansion.

B. Relevant Background

1. What Is a PAL and How Does a PAL Compare to Other Major NSR Requirements and Netting?

The concept of a PAL is simple. Under the Act, you are not subject to major NSR unless you make a ''modification,'' which by definition cannot occur without an emissions increase. CAA section 111(a)(4). A PAL is a source-wide cap on emissions and is one way of making sure that emissions increases from your major stationary source do not occur.

The existing regulations require ''major modifications'' to undergo NSR, and the existence of a ''significant net emissions increase'' at the facility is a necessary prerequisite to a ''major modification.'' *See,* for example, §§ 52.21(b)(2) & (3); *see also Chevron* v. *Natural Resources Defense Council,* 467 U.S. 837, 863–64 (1984). Under our current system, we determine whether a ''significant net emissions increase'' occurs at your major stationary source by focusing initially on the change to the emissions unit(s) and then broadening the analysis to include other changes within the source. In order to determine whether there is a ''significant net emissions increase'' under major NSR as revised today, you must establish a pre-change baseline for each change, project the actual level of emissions after the change, calculate the creditable emissions increases and decreases that have occurred that are contemporaneous with the change, and determine whether the change would result in a significant net emissions increase. We refer to this applicability process as ''netting'' under the major NSR regulations. Both you and reviewing authorities have maintained that the netting rules are unnecessarily complex and burdensome, and have urged us to craft rules that link NSR applicability to compliance with a predictable source-wide emissions cap. We are responding to that request with the PAL concept. A PAL is a voluntary,[28] source-specific, straightforward, flexible approach to account for changes, including alterations to existing emissions units and the addition of new emissions units, at your existing major stationary sources. Complying with the PAL ensures that there are no emissions increases that trigger major NSR. If your emissions of the PAL pollutant remain below the PAL, and you comply with all other PAL requirements, whatever changes occur at your plant will not be subject to major NSR for the PAL pollutant. Our July 23, 1996 proposal contains a thorough discussion of the proposed PAL concept and the background information used to develop the proposal.

2. Why Does EPA Believe That PALs Will Benefit the Environment?

Over the past several years, we have allowed use of major stationary source-wide emissions caps to demonstrate compliance with major NSR in a select number of pilot projects. We recently reviewed six of these innovative air permitting efforts and found substantial benefits associated with the implementation of permits containing emissions caps (among other types of permit terms offering greater flexibility than major NSR permitting programs).[29] Specifically, we reviewed on-site records to track utilization of these flexible permit provisions, to assess how well the permits are working and any emissions reductions achieved, and to determine if there were any economic benefits of the permits.

Overall, we found that significant environmental benefits occurred for each of the permits reviewed. In particular, the six flexible permits established emissions cap-based frameworks that encouraged emissions reductions and pollution prevention, even though such environmental improvements were not an explicit requirement of the permits. We found that in a cap-based program, sources strive to create enough headroom for future expansions by voluntarily controlling emissions. For instance, one company lowered its actual VOC emissions over threefold in becoming a synthetic minor source (that is, 190 tpy to 56 tpy). Other companies lowered their actual VOC emissions by as much as 3600 tpy by increasing capture, by using voluntary pollution prevention and other voluntary emissions control measures, and by reducing production rates.

Participants reported that having the ability to make rapid, iterative changes to optimize process performance in ways that minimize emissions, and that reduce the administrative ''friction'' (time delays and uncertainty) associated with making operational and equipment changes, encourages facilities to make changes that improve yields and reduce per-unit emissions. It is also critical for responding to product development needs and market demand, and for maintaining overall competitiveness.

Reviewing authorities consistently reported that the permits worked well and proved beneficial, and that there was a reduction in the number of case-by-case permitting actions they needed to undertake. Specifically, we found that flexible permit provisions (for example, emissions caps) are enforceable as a practical matter by using a mixture of mass balance-based equations, CEMS, and parameter monitoring. No emissions cap exceedances or violations of the monitoring provisions were experienced by any of the pilot sources. In addition, the monitoring and reporting approaches worked well and were generally of higher quality and of more extensive scope than those directly required by individual applicable requirements.

Based on the results of these pilot projects, we believe that PALs will over time tend to shift growth in emissions to cleaner units, because the growth will have to be accommodated under the PAL cap. Specifically, we expect that PALs will encourage you to undertake such projects as: replacing outdated, dirty emissions units with new, more efficient models; installing voluntary emissions controls; and researching and implementing improvements in process efficiency and use of pollution prevention technologies, so that you can maintain maximum operational flexibility. We also expect that you and the reviewing authority will need to devote substantially fewer resources to

[28] The term ''voluntary'' means that you have the option of entering into a PAL, rather than voluntary compliance with a PAL that is in place. Once you have a permit with PAL requirements, you must comply with the requirements.

[29] Results of our study are reported in ''Evaluation of the Implementation Experience with Innovative Air Permits.'' A complete copy of this report is located in the docket for today's rulemaking.

discussing and reviewing whether major NSR applies to individual changes. Thus, overall, we believe that PALs will prove to be as beneficial to the environment as they are to you and your reviewing authority.

3. What Did We Propose for PALs?

On July 23, 1996, we proposed to amend the NSR regulations to specifically authorize PALs and to clarify the methodology under which you can obtain a PAL. Under the proposal, your reviewing authority could have elected to include provisions in its SIP to allow you to apply for a permit that based your source's major NSR applicability on compliance with a pollutant-specific, source-wide emissions cap. We proposed that a facility's PAL would generally be based on source-wide ''actual emissions'' plus an operating margin of emissions less than a significant emissions increase. We also sought comment on the circumstances under which it would be appropriate to use something other than actual (for example, ''allowable'') emissions to set the PAL.

On July 24, 1998, we published a notice in the **Federal Register** seeking further comment on how the PAL regulations could be reconciled with several environmental and legal concerns. The notice discussed how the PAL alternative fits within the Act's requirements for determining if changes at existing sources are subject to major NSR. Today we are adopting final regulations that address the issues and comments raised in the 1998 notice and the 1996 proposal.

C. Final Regulations for Actuals PALs

Today's action establishes final regulatory provisions for actuals PALs. We are placing these requirements in the major NSR rules for nonattainment areas at § 51.165(f), and in the PSD regulations (applicable in attainment and unclassifiable areas) at §§ 51.166(w) and 52.21(aa).

The PAL option adopted today provides you with a voluntary alternative for determining NSR applicability. Actuals PALs are rolling 12-month emissions caps (that is, tpy limits) that include all conditions necessary to make the limitation enforceable as a practical matter. Through the regulations, we are allowing PALs on a pollutant-specific basis and are also allowing you to opt for actuals PALs for more than one pollutant at your existing major stationary sources. You must continue to apply the major NSR applicability provisions to air pollutants at your source for which you have no PAL.

This section sets forth the specific requirements for actuals PALs. The section addresses the following items: (1) The process used to establish a PAL and the public participation requirements; (2) how the PAL level is determined; (3) how long a PAL is effective and what happens when a PAL expires; (4) can a PAL be terminated before the end of its effective period; (5) how a PAL is renewed; (6) how a PAL can be increased during the effective period; (7) circumstances that would cause your PAL to be adjusted during the PAL effective period; (8) whether a PAL can eliminate enforceable emission limitations previously taken to avoid major NSR; (9) the compliance requirements and monitoring, recordkeeping, reporting, and testing (MRRT) requirements that the permit must contain for emissions units under your PAL; (10) the process for incorporating conditions of the PAL into your title V operating permit; and (11) an example of how an actuals PAL would work under the regulations finalized today.

1. What Are the Permit Application Requirements, What Is the Process Used To Establish a PAL, and What Are the Public Participation Requirements?

Under today's final rules, you must submit a complete application to your reviewing authority requesting a PAL. The application, at a minimum, must include a list of all emissions units, their size (major, significant, or small); the Federal and State applicable requirements, emission limitations and work practice requirements that each emissions unit is subject to; and the baseline actual emissions for the emissions units at the source (with supporting documentation). The calculation of baseline actual emissions must include fugitive emissions to the extent they are quantifiable. The reviewing authority must establish a PAL in a federally enforceable permit (for example, a ''minor'' NSR construction permit, a major NSR permit, or a SIP-approved operating permit program). To comply with our final regulations, the reviewing authority must provide an opportunity for public participation when issuing a PAL permit. This process must be consistent with the requirements at § 51.161 and include a minimum of a 30-day period for public notice and opportunity for public comment on the proposed permit. Where the PAL is established in a major NSR permit, major NSR public participation procedures apply. When establishing a PAL, you must comply with all applicable requirements of the reviewing authority's minor NSR program, including modeling to ensure the protection of the ambient air quality. Additionally, you must meet all applicable title V operating permit requirements. When adding new emissions units under a PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment. In contrast, when adding new emissions units that will require an increase in a PAL, you must comply with the reviewing authority's major NSR permit requirements for public notice, review, and comment.

2. How Is the Level of the PAL Determined?

We calculate the PAL level for a specific pollutant by summing the baseline actual emissions of the PAL pollutant for each emissions unit at your existing major stationary source, and then adding an amount equal to the applicable significant level for the PAL pollutant under § 52.21(b)(23) or under the CAA, whichever is lower.

You must first identify all your existing emissions units (greater than 2 years of operating history) and new emissions units (less than 2 years of operating history since construction). When establishing the actuals PAL level, you must calculate the baseline actual emissions from existing emissions units that existed during the 24-month period as described below. The baseline actual emissions will equal the average rate, in tpy, at which your emissions units emitted the PAL pollutant during a consecutive 24-month period, within the 10-year period immediately preceding the application for a PAL. Consistent with today's final rules, you will have broad discretion to select any consecutive 24-month period in the last 10 years to determine the baseline actual emissions. Only one consecutive 24-month period may be used to determine the baseline actual emissions for such existing emissions units. For any emissions unit (currently classified as existing or new) that is constructed after the 24-month period, emissions equal to its PTE must be added to the PAL level. Additionally, for any emissions unit that is permanently shut down or dismantled [30] since the 24-month

[30] The key determination to be made is whether an emissions unit is ''permanently shut down.'' This issue is discussed in the Administrator's response to a petition objecting to an operating permit for a facility in Monroe, Louisiana. See *Monroe Electric Generating Plant,* Petition No. 6–99–2 (Adm'r 1999). A copy of this decision is in the docket. In general, we explained in our ''reactivation policy'' that whether or not a

period, its emissions must be subtracted from the PAL level. Different rules apply for determining baseline actual emissions for EUSGUs. You should refer to the definition of baseline actual emissions to determine the specific method for calculating baseline actual emissions for your emissions units. Consistent with today's final rules for determining baseline actual emissions, your baseline actual emissions for an emissions unit cannot exceed the emission limitation allowed by your permit or newly applicable State or Federal rules (RACT, NSPS, etc.) in effect at the time the reviewing authority sets the PAL. This means that for the purpose of setting the PAL, your baseline actual emissions for an emissions unit will include an adjustment downward to reflect currently applicable requirements. Additionally, your reviewing authority shall specify a reduced PAL level(s) (in tpy) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. *See* section II of today's preamble for additional information on determining the baseline actual emissions for your emissions units.

3. How Long Can a PAL Be Effective and What Happens When a PAL Expires?

Through the final rules, we are requiring that the term of an actual PAL be 10 years. At least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL, you must submit a complete application either to request renewal or expiration of the PAL. If you meet this application deadline for a permit renewal, the existing PAL will continue as an enforceable requirement until the reviewing authority renews your PAL, even if the reviewing authority fails to issue a PAL renewal within the specified period of time.

As part of an application to request expiration of the PAL, you must submit a proposed approach for allocating the PAL among your existing emissions units. The reviewing authority will retain the ultimate discretion to decide whether and how the allowable emission limitations will be allocated, including whether to establish limits on individual emissions units or groups of emissions units. As under the PAL, your emissions units must comply with their allowable emission limitations on a 12-month rolling basis. However, the reviewing authority retains the discretion to accept monitoring systems other than CEMS, CPMS, PEMS, etc., from you to demonstrate compliance with these unit-specific limits.

Until the reviewing authority issues the revised permit with allowable emission limitations covering each of your emissions units, your source must comply with a source-wide multi-unit emissions cap equivalent to the PAL level. After a PAL expires, physical or operational changes will no longer be evaluated under the PAL applicability provisions.

Notwithstanding the expiration of the PAL, you must continue to comply with any State or Federal applicable requirements for a specific emissions unit. (BACT, RACT, NSPS, etc.) When the PAL expires, none of the limits established pursuant to §§ 51.166(r)(2), 51.165(a)(5)(ii), or 52.21(r)(4), which the PAL originally eliminated, would return under today's final rules.

4. Can a PAL Be Terminated Before the End of Its Effective Period?

Today's final rules do not contain specific provisions related to the issue of terminating a PAL. Decisions about whether a PAL can or should be terminated will be handled between you and your reviewing authority in accordance with the requirements of the applicable permitting program.

5. How Is a PAL Renewed?

As previously discussed, you must submit a complete application to renew a PAL at least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL. If you submit a complete application to renew the PAL by this deadline, the existing PAL will continue as an enforceable requirement until the reviewing authority issues the permit with the renewed PAL. As part of your renewal application, you must recalculate and propose your maximum PAL level, taking into account newly applicable requirements and the factors described below.

Your reviewing authority must review the complete application and issue a proposed permit for public comment consistent with the permitting procedures for issuing the initial PAL. As part of this public process, the reviewing authority must provide a written rationale for its proposed PAL level. If your source's PTE has declined below the PAL level, the reviewing authority must adjust the PAL downward so that it does not exceed your source's PTE.

In addition, the reviewing authority may renew the PAL at the same level without consideration of other factors, if the sum of the baseline actual emissions for all emissions units at your source (as calculated using the definition of ''baseline actual emissions'' at §§ 51.165(a)(1)(xii)(B), 51.166(b)(21), and 52.21(b)(21) as amended by today's final rules) plus an amount equal to the significant level is equal to or greater than 80 percent of the PAL level (unless greater than the current PTE of the major stationary source). However, if the baseline actual emissions plus an amount equal to the significant level is less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, cost effective emissions control alternatives, or other factors as specifically identified by the reviewing authority in its written rationale. For instance, a reviewing authority may determine that PAL levels are inconsistent with the levels necessary to achieve the NAAQS, or a State may determine that PAL levels need to be reduced to provide room for new economic growth in the area.

In some circumstances, such as in the example cited below, the reviewing authority may exercise its discretion in deciding that an adjustment is not warranted. We believe that such discretion is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic

shutdown should be treated as permanent depends on the intention of the owner or operator at the time of shutdown based on all facts and circumstances. Shutdowns of more than 2 years, or that have resulted in the removal of the source from the State's emissions inventory, are presumed to be permanent. In such cases it is up to the facility owner or operator to rebut the presumption.

adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits that operating under a PAL provides, and discourages you from undertaking voluntary reductions. If your source would ordinarily be subject to a downward adjustment, but you believe such an adjustment is not appropriate, you may propose another level. The reviewing authority may approve the level that you propose if it determines, in writing, that the level is reasonably representative of the source's baseline actual emissions. Similarly, the reviewing authority may determine that a lower level best represents the baseline actual emissions from the source.

Consistent with the effective period for the initial PAL, all renewed PALs will have a 10-year effective period.

6. How Can a PAL Be Increased During the Effective Period?

The reviewing authority may allow you to increase a PAL during the effective period if you are adding new emissions units or changing existing emissions units in a way that would cause you to exceed your PAL. However, today's rule only authorizes your reviewing authority to allow such an increase if you would not be able to maintain emissions below the PAL level even if you assumed application of BACT equivalent controls on all existing major and significant units (emissions units that have a PTE greater than a significant amount (as defined by § 52.21(b)(23) or the CAA, whichever is lower). Such units must be adjusted for current BACT levels of control unless they are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level. The PAL permit must require that the increased PAL level will be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

Your proposed new emissions unit(s) and your existing emissions units undergoing a change must go through major NSR permitting, regardless of the magnitude of the proposed emissions increase that would result (for example, no significant level applies). This is because the significant level for the pollutant is incorporated into the PAL. These emissions units must comply with any emissions requirements resulting from the major NSR process (for example, LAER), even though they have also become subject to the PAL program or remain subject to the PAL.

To request a PAL increase, you must submit a complete major NSR permit application. As part of this application, you must demonstrate that the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from your significant and major emissions units (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level), plus the sum of the allowable emissions of the new or modified existing emissions unit(s), exceeds the PAL.

After the reviewing authority has completed the major NSR process, and thereby determined the allowable emissions for the new or modified emissions unit(s), the reviewing authority will calculate the new PAL as the sum of the allowable emissions of the new or modified emissions unit(s), plus the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from significant and major emissions units adjusted for the appropriate BACT level of control as described above. Your reviewing authority must modify the PAL permit to reflect the increased PAL level pursuant to the public notice requirements of §§ 51.166(w)(5), 51.165(f)(5), or 52.21(aa)(5) of today's final rule.

7. Are There Any Circumstances That Would Cause Your PAL To Be Adjusted During the PAL Effective Period?

During the term of the PAL, at PAL renewal or at title V permit renewal, your reviewing authority may reopen your PAL permit and adjust the PAL level, either upward or downward, as needed by the reviewing authority. While certain activities require mandatory reopening, for others the reviewing authority may reopen at its discretion. The reviewing authority must reopen the permit for the following reasons: (1) To correct typographical/calculation errors made in setting the PAL or to reflect a more accurate determination of emissions used to establish the PAL; (2) to reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets; or (3) to revise a PAL to reflect an increase in the PAL.

The reviewing authority may reopen the permit to: (1) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date; (2) reduce the PAL consistent with any other requirement that is enforceable as a practical matter, and that the State may impose on the major stationary source under the SIP; or (3) reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an AQRV that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

While the final rule does not require your reviewing authority to immediately reopen the PAL permit to reflect newly applicable Federal or State regulatory requirements (for example, NSPS, RACT) that become effective during the PAL effective period, it does require the PAL to be adjusted at the time of your title V permit renewal or PAL permit renewal, whichever occurs first. Notwithstanding this requirement, today's final rule provides your reviewing authority discretion to reopen the PAL permit to reduce the PAL to reflect newly applicable Federal or State regulatory requirements before the time we otherwise require.

8. Can a PAL Eliminate Existing Emission Limitations?

An actuals PAL may eliminate enforceable permit limits you may have previously taken to avoid the applicability of major NSR to new or modified emissions units. Under the major NSR regulations at §§ 52.21(r)(4), 51.166(r)(2), and 51.165(a)(5)(ii), if you relax these limits, the units become subject to major NSR as if construction had not yet commenced on the source or modification. Should you request a PAL, today's revised regulations allow the PAL to eliminate annual emissions or operational limits that you previously took at your stationary source to avoid major NSR for the PAL pollutant. This means that you may relax or remove these limits without triggering major NSR when the PAL becomes effective. Before removing the limits, your reviewing authority should make sure that you are meeting all other regulatory requirements and that the removal of the limits does not adversely impact the NAAQS or PSD increments.

We are not taking a position on whether compliance with requirements contained in a PAL permit could serve to demonstrate compliance with certain pre-existing requirements on individual units. The reviewing authority may assess on a case-by-case basis whether any streamlining would be appropriate in the title V permit consistent with part 70 procedures and our existing policies and guidance on permit streamlining.

9. What MRRT (Collectively Referred to as ''Monitoring'') Requirements Must the Permit Contain for Emissions Units Under Your PAL?

Each permit must contain enforceable requirements that accurately determine plantwide emissions. A PAL monitoring system must be comprised of one or more of the four general approaches that meet the minimum requirements discussed below, and such monitoring systems must be approved by the reviewing authority. You may also employ an alternative approach if approved by the reviewing authority. Use of monitoring systems that do not meet the minimum requirements approved by the reviewing authority renders the PAL invalid. Any monitoring system authorized for use in the PAL permit must be based on sound science and must conform to generally acceptable scientific procedures for data quality and manipulation.

In return for the increased operational flexibility of a PAL, your permit must include sufficient data collection requirements to ensure compliance with the PAL at all times. In addition, the PAL permit must contain enforceable provisions that ensure that the monitoring data meet the minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

This section addresses a number of issues associated with the practical enforceability of PALs and describes concepts that you and reviewing authorities must follow when establishing your PAL. The issues addressed include the following.

• How do monitoring requirements for emissions units under a PAL differ from those for emissions units that are not under a PAL?

• What are the testing requirements for your emissions units under a PAL?

• What monitoring systems are appropriate to demonstrate compliance with your PAL?

• What information about your proposed data collection systems must be submitted to your reviewing authority for approval?

• What recordkeeping requirements must your permit contain to demonstrate compliance with your PAL?

• What reporting requirements for your PAL must your permit contain?

a. How Do Monitoring Requirements for Emissions Units Under a PAL Differ From Those for Emissions Units That Are Not Under a PAL?

Typically, when an emission limitation applies on a unit-by-unit basis, the monitoring must be sufficient to provide data that demonstrate that emissions do not exceed the applicable limit for a particular unit. Under this approach, if an emissions unit has to meet an NSPS VOC limit of 9 ppm, the monitoring need only demonstrate that VOC emissions are no higher than 9 ppm but not measure VOC emissions at any precise level below 9 ppm (for example, 7 ppm, 8 ppm).

In contrast, under a VOC emissions actual PAL, the VOC emissions from each emissions unit must be quantified (in tpy), generally each month as the sum of the previous 12 months of VOC emissions. Thus, it becomes necessary to require monitoring that quantifies the emissions from each emissions unit to ensure that the annual limit is enforceable as a practical matter. As a result, the monitoring requirements for emissions units under a PAL may be more stringent than for those emissions units not under a PAL. In many instances, your emissions units may have monitoring suitable for determining compliance with a unit-specific emission limitation on a periodic basis, in accordance with title V requirements, but that monitoring frequency of data collection may not be appropriate for ongoing emissions quantification for a 12-month rolling total. Thus, even if your emissions unit's monitoring meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), you must upgrade that monitoring if you request a PAL and the existing monitoring does not meet the minimum requirements of the PAL regulations.

All units operating under a PAL must have sufficient monitoring to accurately determine plantwide emissions for a 12-month rolling total. For example, a source owner or operator with five units must be able, at any time, to quantify the baseline actual emissions for the past 12 months for each of the five units. That source should, in advance, outline how it plans to monitor each of the units in order to quantify the emissions. If one of the five units cannot accommodate one of the monitoring options provided in the rule in order to quantify the emissions, then the source owner or operator would be incapable of demonstrating ongoing compliance with the source's PAL.

b. What Are the Testing Requirements for Your Emissions Units Under a PAL?

As part of your PAL application and as directed by your reviewing authority, you must use current emissions or other current direct measurement data to demonstrate that your monitoring systems accurately determine emissions from each unit subject to a PAL. You will need to collect such data from all units subject to the PAL, including those that are unregulated at the present time. If you do not have current emissions data, or if your emissions unit's operation and equipment have changed since collection of that data, you will need to obtain current, accurate data, typically by conducting performance tests or other direct measurements before submission of your complete permit application to obtain a PAL.

In addition, you will need to re-validate the data and any correlation to demonstrate that your monitoring systems continue to accurately determine emissions from each unit subject to a PAL. This re-validation must occur at least once every 5 years for the life of the PAL. Data must be re-validated through a performance evaluation test or other scientifically valid means that is approved by the reviewing authority.

You must conduct all testing in accordance with test methods appropriate to your emissions unit and applicable requirements. For example, among the test methods for measuring organic emissions are Methods 18, 25, 25A, and 25B, which can be found in 40 CFR part 60, appendix A. During testing, your emissions unit must operate within the range you wish to operate, so as to provide an accurate quantification of emissions across the entire range. This may require you to perform more than one performance test.

c. What Monitoring Systems Are Appropriate To Demonstrate Compliance With Your PAL?

The PAL monitoring system must be comprised of one or more of four general approaches: (1) Mass balance for processes, work practices, or emissions sources using coatings or solvents; (2) Continuous Emissions Monitoring System (CEMS); (3) Continuous Parameter Monitoring System (CPMS) or Predictive Emissions Monitoring System (PEMS) with Continuous Emissions Rate Monitoring System (CERMS) or automated data acquisition and handling system (ADHS), as needed; or (4) emission factors. Alternatively, another monitoring approach may be used if approved in advance by the reviewing authority. The monitoring approaches mentioned above must meet minimum requirements established by today's rule.

In the mass balance approach, you would consider all of the PAL pollutant contained in or created by any raw material or fuel used in or at your emissions unit to be emitted. Currently, we are limiting this approach to monitoring for processes, work practices, or emissions sources using coatings or solvents. In order to use the mass balance approach, you must validate the content of the PAL pollutant that is contained in or created by any raw material or fuel used on site. This validation may be accomplished by a regular testing program conducted by the vendor of the materials or by an independent laboratory. In addition, you are required to use the upper limit of any content range in the calculations, unless the reviewing authority determines that there is a site-specific data monitoring system in place at the unit or that there are data to support the use of another content within the range.

If your reviewing authority allows you to use a mass balance approach, then the PAL permit must require you to account for all material containing the PAL pollutant or use of all materials that could create PAL pollutant emissions (through chemical decomposition, by-product formation, etc.). For instance, if you are subject to a VOC PAL and your emissions units do not utilize add-on control devices, you may use a mass balance approach to determine compliance. For example, suppose over 1 month you were using 8 tons of solvent with 25 percent VOCs (as demonstrated using Method 311). You would be required to report and include 2 tons of VOC emissions (since $8 \times 0.25 = 2$) for that month to compare with the PAL, even though some of the VOCs may not ultimately be emitted. (For example, they could be retained in your emissions unit's product or in a process waste.)

A CEMS, coupled with a CERMS as well as an ADHS (collectively known as a CEMS), may be used to measure and verify the PAL pollutant concentration, volumetric gas flow (if applicable), and PAL pollutant mass emissions discharged to the atmosphere from each emissions unit emitting the PAL pollutant. If your source utilize a CEMS approach, you must ensure that the CEMS meets the applicable Performance Specifications in 40 CFR part 60, appendix B. The CEMS must be capable of data sampling at least once every 15 minutes. In addition, you must be able to convert the data obtained from the CEMS system to a mass emissions rate.

These types of monitoring systems are appropriate for emissions sources subject to respective SO_2, NO_X, carbon monoxide, particulate matter (PM), VOC, total reduced sulfur (TRS), or hydrogen sulfide (H_2S) regulations.

A CPMS or PEMS coupled with CERMS and ADHS (collectively known as parameter monitoring), may be used for emissions units as reviewed and approved by your reviewing authority.

To determine emissions, parameter monitoring relies on: (1) Use of physical principles; (2) parameters such as temperature, mass flow, or pressure differential; and (3) performance testing results. Users of parameter monitoring must show a correlation between predicted and actual emissions across the anticipated operating range of the unit.

An example is a source owner or operator who determines VOC emissions from an incinerator by multiplying the incinerator efficiency by the amount of VOC-containing material used. Three assumptions are built into the emissions algorithm: (1) The VOC content remains constant; (2) the control device reduction efficiency remains constant over the temperature range established during performance testing; and (3) the unit load remains constant. Checks on these assumptions are established by: ongoing monitoring requirements (for example, combustion chamber temperature and control device load); ongoing emissions testing requirements (for example, periodic re-evaluation of the correlation between combustion chamber temperature and control device efficiency); and ongoing testing of the VOC content of the material.

Another example of parameter monitoring is an organic emissions condenser. The parameter monitoring design in this case is based on the laws of physics and the physical properties of the material (for example, the lowest condensation temperature of the VOC constituent), the temperature of the condenser, and the maximum material feed rate.

Some parameter monitoring works by calculating emissions using data from monitored parameters and a neural network system to optimize performance of a unit. By measuring numerous parameters, the network can then automatically analyze current operations, as well as emissions, and make adjustments to optimize performance.

Establishing parameter monitoring is a resource-intensive effort, requiring extensive up-front testing, analysis, and development. Recently, we have developed draft performance specifications for evaluating appropriate, acceptable parameter monitoring accuracy, repeatability, and reproducibility (*e.g.*, Performance Specification 16). You and your reviewing authority should review these performance specifications in developing an interim protocol for using parameter monitoring to demonstrate continuous compliance with a PAL. Your approved protocol may require revision as we finalize performance specifications.

Today's rule requires you to re-validate your monitoring systems, including parameter re-certification emissions testing, at least once every 5 years during the PAL permit term. You may conduct such re-validation as part of any other testing required by other non-PAL program requirements, such as title V program requirements.

If a parameter monitoring approach is taken, the owner or operator must use current site-specific data to establish the emissions correlations between the monitored parameter and the PAL pollutant emissions across the entire range of the operation of the emissions unit. If the owner or operator cannot establish a correlation for the entire operation range, the reviewing authority shall, at the time of the permit issuance, establish a default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated during the operational times when an emissions correlation is not available.

Alternatively, the reviewing authority may decide that operation of the emissions unit during periods where there is no emissions correlation is a violation of the PAL. The PAL permit must include enforceable requirements if either of these alternatives to the required correlation for parameter monitoring are used.

Emission factors may be used for demonstrating compliance with PALs, so long as the factors are adjusted for the degree of uncertainty or limitations in the factors' development. In ascertaining whether an emission factor is appropriate, you and your reviewing authority should consider the contribution of emissions from the emissions unit in relation to the PAL, the size of the emissions unit, and the margin of compliance of the emissions unit. In addition, if the emission factor approach is taken, the emissions unit shall operate within the designated range of use for the emission factor.

The owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing using other monitoring approaches (if technically practicable) to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required. For example, should you demonstrate to your reviewing authority's satisfaction that the use of your emission factor would yield a result that is protective of the environment, then you may not need to conduct site-specific performance testing. An emissions unit is considered significant if the emissions unit has the potential to emit the PAL pollutant in amounts greater than those listed in § 51.165(a)(1)(x).

In the event you choose to use one or more emission factors for your significant or small emissions units, you bear the burden to prove to the reviewing authority that the emission factors are appropriate and adjusted for any uncertainty in the factors' development. By way of example, the sulfur dioxide emission factor for 2-stroke, lean-burn, natural gas fired reciprocating engines, $5.88 * 10^{-4}$ pounds of sulfur dioxide emitted per million British Thermal Unit (mmBTU) of natural gas combusted, as published in our *Compilation of Air Pollutant Emission Factors AP–42, Fifth Edition Volume 1: Stationary Point and Area Sources,* which is found on our Internet Web site at *http://www.epa.gov/ttn/chief/ap42/index.html,* represents an appropriate emission factor.

The reviewing authority may approve other types of monitoring systems that quantify emissions to demonstrate compliance with PALs. Other types of monitoring that may be approved include a Gas Chromatographic (GC) or a Fourier Transform Infrared Spectroscopy (FTIR) CEMS that relies on extractive techniques, coupled with a CERMS as well as an ADHS, to measure and verify the VOC concentration, volumetric gas flow (if applicable), and VOC mass emissions (in lb/hr) discharged from stacks (that is, non-fugitive emissions) to the atmosphere. For processes, work practices, or emissions sources subject to VOC or organic hazardous air pollutant (HAP) regulations, these types of monitoring systems may be used for each emissions unit emitting VOC.

d. *What information about your monitoring system must be submitted to your reviewing authority for approval?*

You need to propose a monitoring system as part of your PAL permit application submission to your reviewing authority. The monitoring system proposed must accurately determine plantwide emissions. In your permit application, you must describe how you will collect and transform data from each emissions unit subject to a PAL permit, so that the emissions from each unit can be quantified as a 12-month rolling total. In addition, you need to demonstrate how you can be assured the data are and remain accurate by describing how you will install, operate, certify, test, calibrate, and maintain the performance of your monitoring system(s) on each emissions unit that will be subject to the PAL.

You will also need to provide calculations for the maximum potential emissions without considering enforceable emission limitations or operational restrictions for each unit in order to determine emissions during periods when the monitoring system is not in operation or fails to provide data. In lieu of the permit requiring maximum potential emissions during periods when there is no monitoring data, you may propose another alternate monitoring approach as a backup. This backup monitoring, however, must still meet the minimum requirements for the monitoring approaches prescribed in the regulation.

Note that each monitoring system with applicable requirements contained in appendix B of 40 CFR part 60 must be installed, operated, and maintained according to the applicable Performance Specification of 40 CFR part 60, appendix B.

For purposes of determining emissions from an emissions unit, a unit is considered operational not only during periods of normal operation, but also during periods of startup, shutdown, maintenance, and malfunction'even if compliance with a non-PAL emission limitation is excused during these latter periods. Your reviewing authority may approve different monitoring for various operating conditions (for example, startup, shutdown, low load, or high load conditions as demonstrated through multiple performance tests) for each emissions unit. You must, however, use one of the accepted monitoring approaches, including alternative monitoring approved by the reviewing authority, for these periods or calculate the emissions during these periods by assuming the highest PTE without considering enforceable emission limitations or operational restrictions.

In addition, the rule permits the reviewing authority to use the reasonably estimated highest potential emissions for periods when your emissions unit operates outside its parameter range(s) established in the performance test, unless another method is specified in the permit, and include those emissions in the 12-month rolling total in order to demonstrate compliance with the PAL. Alternatively, the reviewing authority may decide that operation outside the range(s) established in the performance test is a violation of the PAL. The reviewing authority must decide how to handle emissions when the unit is operating outside the ranges established in the performance tests prior to the issuance of the PAL permit and must include appropriate enforceable conditions in the PAL permit.

For parameter monitoring to be approved by your reviewing authority, your proposed monitoring system must measure the operational parameter value(s) within the established site-specific range(s) of operating parameter values demonstrated in recent performance testing. The monitoring system must then record the associated PAL pollutant mass emissions rate for that period based on the correlations demonstrated with the current test data.

e. What Recordkeeping Requirements Must Your Permit Contain To Demonstrate Compliance With Your PAL?

Your permit must require you to maintain records of your monitoring and testing data that support any compliance certifications, reports, or other compliance demonstrations. This information should contain, but is not necessarily limited to, the following data.

- The date, place (specific location), and time that testing or measuring occurs
- The date(s) sample analysis or analyses occur
- The entity that performs the analysis or analyses
- The analytical techniques or methods used
- The results of the analyses
- Each emissions unit's operating conditions during the testing or monitoring
- A summary of total monthly emissions for each emissions unit at the major stationary source for each calendar month
- A copy of any report submitted to the reviewing authority
- A list of the allowable emissions and the date operation began for any new emissions units added to the major stationary source.

You must also record all periods of deviation, including the date and time that a deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction.

You must retain records of all required testing and monitoring data, as well as supporting information, for at least 5 years from the date of the monitoring sample, measurement, report, or application. Supporting information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all required reports. Instead of paper records, you may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review and does not conflict with other recordkeeping requirements.

You must also retain a copy of the following records for the duration of the PAL effective period plus 5 years: (1) A copy of the PAL permit application and any applications for revisions to the PAL; and (2) each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

f. *What reporting requirements for your PAL must your permit contain?*

You must provide semi-annual monitoring and prompt deviation reports. The terms and conditions of an approved PAL become title V applicable requirements that will be placed in your title V permit. Therefore, the reports required under title V may meet the requirements of the PAL rule, so long as the minimum reporting requirements listed in the regulations are met. You must submit a semi-annual emissions report to the reviewing authority within 30 days after the end of each reporting period. The reviewing authority will use this report to determine compliance with the conditions of the PAL, including the PAL level.

The compliance period for an actuals PAL emissions level is a consecutive 12-month period, rolled monthly. Block 12-month periods are not allowed (for example, Jan.-Dec. of each year). The emissions report must include the total baseline actual emissions of the PAL pollutant for the previous 12 months and compare the previous 12 months' total emissions with the PAL level to determine compliance. Additionally, the emissions report must identify: the site; the owner or operator; the applicable PAL; the monitored parameters, the method of calculation with appropriate formulas, any emission factors used, the capture and control efficiencies used and the calculated emissions; total monthly emissions (tons) and the equations used to compute this value for each of the 12 months before submission of the emissions report (or for all prior months if the PAL has not been effective for 1 year); total annual emissions (tpy); a PAL compliance statement; a list of any emissions units added or modified to the site; and information concerning shutdown of any monitoring system, including the method that was used to measure emissions during that period. Finally, in accordance with title V requirements, your permit will require all reports to be certified by your responsible official as true, accurate, and complete.

10. What is the process for incorporating conditions of the PAL into your title V operating permit?

As discussed previously, the reviewing authority establishes a PAL in a federally enforceable permit using its minor NSR construction permit process or the major NSR permit construction process and eventually rolling these requirements into its title V operating permit. The reviewing authorities' rules for establishing or renewing PALs must include a public participation process prior to permit approval of the PAL. The process must be consistent with the requirements at § 51.161 and include a minimum 30-day period for public notice and opportunity for public comment on the proposed permit. PALs established through the major NSR process are subject to major NSR public participation requirements. When adding a new emissions unit under an established PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment.

The process for incorporating the conditions of a PAL into the title V operating permit depends on whether the initial title V permit has already been issued for the source. If the initial title V permit has not been issued, a PAL created in a minor or major NSR permit would be incorporated during initial issuance of the title V permit. If the initial title V permit has already been issued, the PAL would be incorporated through the appropriate part 70 modification procedures. As discussed later in this preamble, we suggest that you request that your reviewing authority renew your title V permit concurrently with issuance of your PAL in order to align the two processes together and decrease the administrative burden on you and your reviewing authority.

Once a PAL is established, a change at a facility is exempt from major NSR and netting calculations, but could require a title V permit modification, as could any other change. Whether a title V permit modification would be required, and which permit modification process would be used, is governed by the current part 70 rule as implemented by the reviewing authority.

11. What is an example of an actuals PAL?

The following example is based upon a hypothetical source that wishes to obtain an actuals PAL under the final regulations adopted today.

A manufacturing plant (a major stationary source) located in a serious ozone nonattainment area seeks an actuals PAL for VOC in January 2002. The major source threshold for VOC in a serious ozone nonattainment area is 50 tpy and the significant level for VOC modifications is 25 tpy. The plant has 5 emissions units with a total PTE of 640 tpy of VOC. The PTE for VOC for each of the emissions units at the plant is as follows: (1) Unit A is 335 tpy; (2) unit B is 20 tpy; (3) Unit C is 125 tpy; (4) unit D is 60 tpy; and (5) unit E is 100 tpy. Units A, B, C, and D are existing emissions units with more than 2 years of operating history. Unit E has been in operation for only a year. Unit D was dismantled in year 2000 and is considered permanently shutdown.

For units A, B, C, and D, the source has selected July 1, 1996 to June 30, 1998 (a consecutive 24-month period) to determine baseline actual emissions. Unit A is subject to a RACT requirement that became effective in year 2000. The baseline actual emissions for each emissions unit during this period are as follows: unit A, 140 tpy (including RACT adjustment); unit B, 10 tpy; unit C, 90 tpy; and unit D, 20 tpy.

The actuals PAL level for VOC is = 260 + 100 ¥ 20 + 25 = 365 tpy

WHERE

• 260 tpy = the sum of the baseline actual emissions for emissions units A–D (with 2 or more years of operation)
• 100 tpy = the allowable emissions (PTE) of unit E, which was constructed after the 24-month period;
• 20 tpy = baseline actual emissions of unit D, which is permanently shut down since the 24-month period; and
• 25 tpy = significant level for VOC in a serious nonattainment area.

D. Rationale for Today's Final Action on Actuals PALs

We received voluminous comments and suggestions in response to the 1996 NSR proposal, the 1998 NOA, and numerous meetings with interested stakeholders. This section addresses the more significant comments we received. For a more detailed discussion of the comments received and our responses, please refer to the Technical Support Document included in the docket for this rulemaking. The comment areas addressed in this section include: (1) How do the PAL regulations meet the major NSR requirements of the Act? (2) Are PALs consistent with the concept of ''contemporaneity''? (3) Are PALs permissible in serious and severe nonattainment areas? (4) Is it appropriate for a PAL to be based on actual emissions? (5) How should actual emissions be determined in setting the PAL level? (6) Should emissions from shut down or dismantled units be excluded from a PAL? (7) Should a PAL include a margin for growth? (8) Should PALs be required to expire? (9) Should we require PALs to be adjusted at the time of PAL renewal? (10) Should certain new emissions units that are added under a PAL be required to meet some level of emissions control? (11) Under what circumstances should you be allowed to increase your PAL and how should we apply the major NSR requirements to that increase? (12) What monitoring requirements are necessary to ensure the enforceability of PALs as a practical matter? (13) Is EPA adopting an approach that allows area-wide PALs? and (14) When should modeling or other types of ambient impact assessments be required for changes occurring under a PAL?

1. How do the PAL regulations meet the major NSR requirements of the Act?

The PAL regulations adopted today meet the requirements of the CAA and are consistent with the Congressional purpose and intent underlying NSR. We believe the PAL regulations constitute a reasonable interpretation of the Act's definition of ''modification'' and are permissible under current law.

The definition of ''modification'' set forth in section 111(a)(4) of the Act is fundamental to determining major NSR applicability. Pursuant to the Act, the term modification means ''any physical change in or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' The statute, however, does not prescribe the methodology for establishing a stationary source's emissions baseline from which emissions increases are measured. When a statute is silent or ambiguous with respect to specific issues, the relevant inquiry is whether the agency's interpretation of the statutory provisions is permissible. *Chevron U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 865 (1984).

Accordingly, EPA is exercising its discretion to develop reasonable alternatives to determine NSR applicability that are consistent with the statutory provisions and Congressional intent underlying the NSR requirements. We believe that the PAL regulations adopted today represent a permissible construction of the Act.

2. Are PALs consistent with the concept of ''contemporaneity''?

In the 1998 NOA, we solicited comment on whether and how a program that recognizes PALs as an alternate method for determining NSR applicability should address a particular legal concern: the need to have some ''contemporaneity'' between an emissions increase and any decrease relied upon to net the increase out of review. As we discussed in the 1998 notice, the current regulations specify that, to be creditable, emissions increases and decreases must have occurred within a ''contemporaneous'' period. Our current regulations governing SIP-approved programs do not specify a precise time frame. However, the Federal PSD rules generally only credit those emissions increases and decreases that occur within the 5 years preceding a given change. We established these regulatory requirements after the court's decision in *Alabama Power,* in which the court interpreted the Act as requiring plantwide bubbling in the PSD program, but stated that ''any offset changes claimed by industry must be substantially contemporaneous.'' 636 F.2d 402. In the 1998 notice, we sought comment on whether a PAL program that never required PALs to be periodically updated to reflect current emissions at the source would allow sources to make emissions reductions and hold them indefinitely, only to use them several decades later to offset new increases, and whether such a system would contravene the contemporaneity principle the court announced.

Many commenters, including several regulatory agencies, maintain that PALs are consistent with the NSR requirements under the Act. These commenters contend that the court gave EPA the discretion to define contemporaneity. See 636 F.2d 402 (''The Agency has discretion, within reason, to define which changes are substantially contemporaneous.''). Others contend that changes made under a PAL are not subject to the *Alabama Power* ''contemporaneity'' requirement because a change made under the PAL is either excluded from NSR or alternatively does not exceed the applicable NSR significance threshold. Therefore, they contend that netting is not implicated by such changes. On the other hand, a few commenters assert that PALs conflict with the purpose of the Act.

We believe that the concept of contemporaneity, as articulated in *Alabama Power* and as set forth in the regulations governing the major NSR program, does not apply to PALs. The PAL program differs in certain important respects from our current regulations and from the 1978 regulations at issue in *Alabama Power.* The *Alabama Power* court was not presented with the PAL approach for determining whether there was an increase in emissions and did not consider whether the principles it set forth in its opinion would apply to such an approach.

Under the 1978 PSD regulations (43 FR 26380), a source was subject to BACT review only if ''no net increase in emissions of an applicable pollutant would occur at the source, taking into account all emissions increases and decreases at the source which would accompany the modification.'' 43 FR 26385. The test for whether a ''major modification'' had occurred required the source to sum all accumulated increases in potential emissions that had occurred at the source since issuance of the regulations, or since issuance of the last construction permit, whichever was more recent. Reductions achieved elsewhere in the source could not be taken into account.

In *Alabama Power,* the D.C. Circuit held that EPA was correct in excluding from BACT review any changes that did not result in a net increase of a pollutant. 636 F.2d 401. It concluded, however, that EPA had incorrectly excluded contemporaneous decreases from the calculation of whether a ''major modification'' had occurred. *Id.* at 402–03.

The current regulations take contemporaneous decreases into account for all PSD review purposes. Under the current regulations, you look initially at the emissions unit undergoing the change and determine whether there will be a significant increase at that unit. If there is no significant increase at the unit, the inquiry ends there. While we continue to believe that this is a permissible approach, one drawback to this approach is that it allows a series of small, unrelated emissions increases to occur, which is discussed elsewhere in this preamble. If there will be a significant increase at the unit, then you expand the inquiry to other units at the source. You take into account contemporaneous increases and decreases at the source in determining whether there will be an increase for the source as a whole. Thus, you must calculate increases and decreases at individual units in order to arrive at a net figure for the entire source.

In contrast, under today's PAL regulations, the inquiry begins and ends with the source. Your PAL represents source-wide baseline actual emissions. As such, it is the reference point for calculating increases in baseline actual emissions. If your source's emissions will equal or exceed the PAL, then there will be an emissions increase at your source. There is no need to calculate increases and decreases at individual units.

Today's PAL regulations constitute a reasonable, though not the only, approach to determining whether there is an emissions increase at your source. While we believe that the principle of contemporaneity continues to be important for purposes of major NSR netting calculations, we do not believe that it is a necessary concept for purposes of PALs. This is because if your source has a PAL, you have accepted a different means of calculating an emissions increase for the PAL pollutant. The only relevant question is whether your source has reached or exceeded the PAL level.

Even though PALs are a new approach, they do not alter the fundamental question, which is whether there will be an increase in emissions from your source. For actuals PALs, we consider whether there will be an increase in baseline actual emissions. Because the PAL serves as the baseline for measuring an increase, we have taken steps to ensure that the PAL is reasonably representative of baseline actual emissions. In taking these steps, we have also ensured that actuals PALs as finalized today are consistent with the concept of contemporaneity, to the extent such a concept has any application in this context. One way of viewing a PAL is to focus on the increases and decreases at individual emissions units that, taken together, result in the net emissions from your source as a whole. As long as the decreases that have occurred during the term of the PAL are sufficient to offset any increase that occurs, total emissions for your source will remain below the PAL, and your source will not experience a ''significant net emissions increase.'' Viewed from this perspective, the term of the PAL constitutes the ''contemporaneous'' period. We believe that 10 years is a reasonable contemporaneous period for PALs for the following two reasons. First, we believe that a 10-year period is practical and reasonable both for you and for the reviewing authority. While a logical stopping point may seem to be 5 years in line with the title V permit period, setting a PAL can be a complex and time consuming process, so a 5-year period would be too short and hence not beneficial either to you or to the reviewing authority. Second, a study conducted by Eastern Research Group, Inc.[31] supported a 10-year look back to ensure that the normal business cycle would be captured generally for any industry.

In addition, we believe that the PAL renewal provisions ensure that each 10-year term represents a distinct ''contemporaneous'' period. The renewal process is designed to prevent decreases that occurred outside of the current 10-year PAL term from being used to offset increases during that term. At renewal, the reviewing authority must consider whether decreases have occurred at your source because of compliance with newly applicable requirements. Thus, for example, if the compliance date for a new RACT requirement occurred during the initial term of the PAL, and the reviewing authority has not already adjusted the PAL downward to account for that requirement, it must do so at renewal. More generally, the reviewing authority is required to evaluate baseline actual emissions and provide a written rationale for public comment if it determines that an adjustment to the PAL is warranted. As part of this process, the reviewing authority must adjust the PAL downward if your source's current PTE is below the PAL level. We believe that this adjustment is important for air quality planning purposes. Additionally, the reviewing authority may renew the PAL at the same level if your source's baseline actual emissions plus the significant level are equal to or greater than 80 percent of the PAL level without consideration of other factors. We believe that this level is reasonably representative of the source's baseline actual emissions. If your source's baseline actual emissions plus the significant level are less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale. We recognize that fluctuations in baseline actual emissions will occur at most sources as part of the normal business cycle. We also recognize that requiring the reviewing authority to adjust the PAL downward if your source's baseline actual emissions do not equal 100 percent of the PAL level could create an incentive for you to maximize your baseline actual emissions. In addition, most sources do not emit at a level just below the maximum allowable level but rather build in a margin to prevent accidental exceedances. However, the PAL should be reasonably representative of baseline actual emissions so that it can continue to serve as the baseline for calculating an emissions increase. We have balanced these competing concerns in adopting a requirement, subject to the provisions noted below, to provide discretion to the reviewing authority to adjust the PAL level if baseline actual emissions plus the significant level do not equal at least 80 percent of the PAL level.

To maintain flexibility, today's actuals PAL regulations allow the reviewing authority to determine representativeness on a case-by-case basis. If you believe that the new PAL level that the reviewing authority proposes for your source is not representative of your source's baseline actual emissions, you may propose a different level. In addition, any person may propose a different level as being more representative of your source's baseline actual emissions. The reviewing authority may approve a higher or lower level if it determines that it is reasonably representative of your source's baseline actual emissions.

For example, assume that your source was designed to burn either fuel oil or natural gas, and that your source's permit allowed the use of either fuel. During the initial term of the PAL, you used only natural gas at the source and your source-wide emissions were consistently less than 80 percent of the PAL level. However, due to shifting market conditions, you expected to use fuel oil for a period beginning after PAL renewal. Under these circumstances, the reviewing authority could reasonably determine that a higher level would be more representative of your source's baseline actual emissions.

Similarly, your source might be designed to manufacture several different products, and your permit might allow you to switch from one product to another. During the initial term of the PAL, you might produce a

[31] Eastern Research Group Inc. report on ''Business Cycles in Major Emitting Source Industries'' dated September 25, 1997.

product associated with low emissions, resulting in source-wide emissions that were consistently less than 80 percent of the PAL level. However, you might be planning to produce a product that would cause the source to emit at a higher level following PAL renewal. This is another example of a circumstance in which the reviewing authority could reasonably determine that a higher level was more representative of your source's baseline actual emissions.

In addition, for SIP planning purposes, the reviewing authority may adjust the PAL level at its discretion based on air quality needs, advances in control technology, anticipated economic growth in the area, or other relevant factors.

Because of the safeguards described above, we believe that the actuals PAL program as finalized today ensures that the PAL will serve as an appropriate baseline for determining whether there is a significant net ''increase'' in overall emissions from the source, and thus whether the source is undergoing a ''modification.''

Moreover, we believe that a PAL approach satisfies Congressional intent to only apply the NSR permit process when industrial changes cause significant net emissions increases to an area and not when changes in plant operations result in no emissions increase from the major stationary source. *See Alabama Power,* 636 F.2d 401.

3. Are PALs Permissible in Serious, Severe, and Extreme Ozone Nonattainment Areas?

In our 1996 proposal, we requested comment on whether PALs could be implemented in serious and severe ozone nonattainment areas in a manner that was consistent with section 182(c)(6) of the Act. Section 182(c)(6) contains special provisions for major stationary sources that increase VOC emissions in serious or severe ozone nonattainment areas as a result of a physical change or a change in the method of operation. In some of these areas, the provisions also apply if you increase NO_X emissions. In general, these special provisions change the significant level for VOC emissions in serious and severe nonattainment areas from 40 tpy to greater than 25 tpy. They also specify that you must go through a major NSR permitting review if you have a net emissions increase in the aggregate of more than 25 tpy over a period of 5 years.

In addition, we requested comment on whether PALs could be implemented in extreme ozone nonattainment areas. Section 182(e)(2), which applies in such areas, provides that any physical change or change in the method of operation at the source that results in ''any increase'' from any discrete operation, unit, or other pollutant-emitting activity at the source, generally must be considered a modification subject to major NSR permit requirements, regardless of any decreases elsewhere at the source.

A few industry commenters believe that the ''accumulation'' provisions of CAA section 182(c)(6) should make no difference to the acceptability of a PAL in ''serious'' and ''severe'' ozone nonattainment areas. They contend that we have correctly concluded that CAA section 182(c)(6) only applies when net emissions at the source as a whole increase above the 25 ton level. Accordingly, any change that triggered CAA section 182(c)(6) would already have breached the PAL limits. On the other hand, an environmental commenter states that a PAL in a serious, severe, or extreme ozone nonattainment area could be problematic because it could allow for an increase at an emissions unit in situations where source-wide emissions would not exceed the PAL.

We agree with commenters who believe that the PAL approach does not conflict with the provisions of CAA section 182(c)(6). We do not interpret section 182(c)(6) to be a limitation on our ability to authorize PALs in serious and severe nonattainment areas. This section directs that when there is an increase meeting certain criteria, it may not be considered *de minimis*, but it does not specify the methodology by which an emissions increase must be calculated. Accordingly, we exercise our discretion in establishing the methodology, and we are doing so today by having the PAL serve as the actuals emissions baseline against which future emissions increases are measured. *Chevron U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 865 (1984). If your source's emissions equal or exceed the PAL, it will trigger NSR, whereas maintaining plant emissions below the PAL ensures that there is no emissions increase. We believe that our interpretation reasonably implements the statutory purpose of the section, given that PAL sources agree to be subject to a plantwide cap that serves as the reference point for determining whether there has been an increase and given that the appropriateness of the PAL level is reviewed at 10-year intervals. Actuals PALs effectively prevent the uncontrolled, unrelated, small, serial emissions increases section 182(c)(6) is designed to address.

Because CAA section 182(e)(2) clearly requires consideration of increases at individual emissions units in extreme ozone nonattainment areas, PALs are not allowed in such areas, since any increase in emissions from any unit in those areas constitutes a modification.

4. Is It Appropriate for a PAL to Be Based on Actual Emissions?

In 1996, we proposed and sought comment on a broad range of alternative approaches for setting PAL emission limitations, including a PAL based on the following: (1) Actual emissions as defined under the current and then proposed regulations at § 51.166(b)(21)(ii); (2) actual emissions with the addition of an operating margin greater than the applicable significance rate; (3) for new stationary sources, limits established pursuant to a review of the entire facility under PSD; and (4) for nonattainment pollutants (in nonattainment areas), any emissions level completely offset and relied upon in an EPA-approved State attainment demonstration plan. 61 FR 38250, 38256 (July 23, 1996).

We received general support for the PAL concept and for the different approaches we proposed. Some comments express support for a PAL approach based on allowable emissions, and others indicate support for a PAL approach based on actual emissions. Some commenters generally believe that an allowables approach is necessary to ensure increased operating flexibility and capacity utilization. They also assert that an allowables approach would protect air quality management goals, because they claim that air quality planning historically has been based on permitted emissions levels. Other commenters believe that an actuals approach is preferable because it facilitates more accurate air quality planning and provides a more reliable basis for determining the availability of offsets.

We have concluded that a major stationary source's compliance with an actuals-based PAL system is a permissible means of assuring that a major stationary source does not have a significant emissions increase. We also conclude that this approach can be implemented in a manner that is consistent with the Act. Thus, in today's action, we are adopting regulations that authorize States to issue actuals PALs. We plan to address allowables PALs in an upcoming rulemaking.

5. How Should Actual Emissions Be Determined in Setting the PAL Level?

In the 1996 proposal, we requested comment on whether the definition of actual emissions for the purpose of determining the level of the PAL should be based on the definition of actual emissions in the current major NSR regulations, or whether it should be based on the proposed revisions to the actual emissions definition contained in that 1996 proposal. The fundamental difference between these two approaches is that the current NSR regulations would only allow you to look back 5 years to determine the actual emissions (the sum of actual emissions for all emissions units at your major stationary source). The 1996 proposed changes to this definition would allow you to look back 10 years to determine the actual emissions.

Several commenters prefer a 10-year baseline period for setting PALs based on actual emissions. A few commenters prefer a 5-year baseline period. One commenter advocates use of an actual emissions level that is initially based on the previous 2 years but that would decline over time.

In a separate section of today's final rules, we are finalizing changes to our definition of baseline actual emissions. Among other changes to the definition, you will be allowed to look back for a period of 10 years to establish the baseline actual emissions (except for EUSGUs). For program consistency and ease of implementation, we believe that the procedure for determining the baseline actual emissions for establishing your PAL should be the same as the baseline actual emissions that you will be required to use under the other major NSR program requirements. Accordingly, we are adopting an approach for establishing your actuals PAL that is consistent with how the baseline actual emissions are determined for an emissions unit under other requirements of the major NSR program.

We are, however, including a special allowance for emissions units that have operated for less than 2 years. Under such circumstances, the emissions unit has not operated long enough to establish a reliable baseline actual emissions calculation. Therefore, today's rule allows your reviewing authority to consider the allowable emissions of such emissions units when establishing or renewing the PAL. The baseline actual emissions of such emissions units would be adjusted to reflect a more representative level of baseline actual emissions at the time of the next PAL renewal.

6. Are Emissions From Shut Down or Dismantled Units Excluded From a PAL?

We proposed several options to adjust PAL levels to account for emissions units that are shut down or dismantled before setting a PAL. Several commenters support adjusting the PAL level for permanently shut down or dismantled units. A few commenters maintain that PAL adjustments are only appropriate for long-term shutdowns. Other commenters oppose allowing adjustments for shutdowns. They indicate that it would be difficult to implement and that it could penalize sources that were meeting environmental goals.

We agree with commenters that the baseline actual emissions used in establishing the PAL should exclude emissions from units that are permanently shut down or dismantled after the 24-month period selected for establishment of baseline emissions. We believe that excluding such emissions from your PAL level is appropriate for air quality planning purposes. Moreover, the environment has already seen the benefit of the reduced emissions. We also do not agree with those commenters who advocate adjusting the PAL only for long-term shutdowns, because it is too difficult to define and enforce ''long-term.''

As described in section IV.C.2 of this preamble, the PAL level includes baseline actual emissions from each existing emissions unit and new emissions unit at the source. For any emissions unit that has been permanently shut down since the 24-month period, its emissions should not be included in calculating the PAL level. Conversely, for an emissions unit that began construction after the 24-month period, the emissions (equal to the potential emissions of that emissions unit) must be included in setting the PAL level.

One shutdown option we considered, but did not adopt, is to exclude emissions from PALs only for units that did not operate at all during the 10-year life of the PAL. Under this option, the PAL would not be adjusted downward if you utilized those emissions from the shut down or dismantled units elsewhere at your source during the period since the shutdown (for example, by adding new emissions units or capacity, or by increasing capacity utilization at existing emissions units). As we indicated in our proposal, we believe it would be too difficult to determine whether you have actually relied on these emissions decreases in undertaking other activities at your source. We did not receive any comments suggesting ways to overcome this identified problem.

7. Does a PAL Include a Reasonable Operating Margin?

In the July 23, 1996 action, we proposed that a PAL for existing sources be based on source-wide actual emissions, including a reasonable operating margin less than the applicable significant emissions rate. We also requested comment on several other options for establishing a PAL. Several commenters support the option of basing the PAL on source-wide actual emissions plus a reasonable operating margin less than the applicable significance amount. Other commenters believe an operating margin tied to significant levels would be too restrictive.

Today we are finalizing an option that allows you to include, when setting the initial PAL, an amount that corresponds to the significant level for modifications of the PAL pollutant as specified in the major NSR rules [for example, in the PSD regulations at § 52.21(b)(23)(i)], or as specified in the CAA, whichever is lower. For example, for SO_2 PALs you may add to the PAL baseline level the 40 tpy significant level; for CO PALs you may add 100 tpy to the PAL baseline level. Also, for serious and severe ozone nonattainment areas the VOC significant level added to the PAL level is 25 tpy. For major sources of NO_X located in serious and severe ozone nonattainment areas, where NO_X is regulated as an ozone precursor, you may add to the NO_X PAL baseline the NO_X significant level of 25 tpy, and not the 40 tpy NO_X significant level specified under PSD. In extreme ozone nonattainment areas, PALs are not allowed since any increase in emissions in these areas constitutes a modification.

While other approaches to providing a reasonable operating margin may be consistent with the CAA, we believe that the approach we are adopting today comports most closely with existing regulatory provisions for major NSR applicability. That is, it assures that the environment sees no significant increases in emissions compared to the baseline actual emissions existing before the PAL is established.

In our 1998 NOA, we also requested comment on whether we should provide for an operating margin when renewing a PAL. We proposed four possible approaches for maintaining a reasonable operating margin, including an option that would include in the adjusted PAL level an operating cushion equal to 20 percent of the current PAL. In a separate section of the NOA, we also requested comment on how PALs should be adjusted for emissions units that have installed good emissions controls.

Many commenters indicate that we must provide for a reasonable operating margin. However, we generally received unfavorable comments on all the approaches we suggested. Several commenters believe that our suggested approaches do not provide an adequate operating margin. In responding to our request for comment on how to adjust PALs for emissions units that have installed good emissions controls, many commenters indicate that it would be inappropriate for EPA to ''confiscate'' such emissions reductions. Such an approach would encourage sources to pollute to maintain higher baseline emissions, and would penalize those sources who would voluntarily reduce emissions. At least one commenter maintains that both you and the environment should benefit from these reductions, and thus, you should be allowed to retain a portion of your voluntary emissions reductions.

We agree with some commenters that mandating an adjustment at renewal, based solely on current operations and emissions levels, would discourage the voluntary emissions reductions the PAL is specifically designed to encourage. We agree with commenters that both you and the environment should benefit from your commitment to comply with a PAL. Should you engage in voluntary emissions reductions, we believe you should be able to retain the accompanying flexibility that encouraged you to make these reductions. At the time of renewal, it may be very difficult for a reviewing authority to distinguish the reason for a decrease in your baseline actual emissions level. It could be because you have aggressively applied emissions controls, or because of a decrease in utilization, a loss of capacity, a desire to maintain a compliance margin, or any of a number of other reasons. Accordingly, we believe that it would be difficult to advise a reviewing authority to only retain a certain percentage of your emissions reductions that resulted from applying emissions controls. Therefore, for simplicity, and for what we believe to be a reasonable policy position to encourage you to voluntarily reduce emissions without a fear of a complete loss of operational flexibility, we are allowing your reviewing authority discretion to renew the PAL at an appropriate level. Hence, your reviewing authority may renew the PAL at the same level without consideration of other factors, if the baseline actual emissions plus the significant level is equal to or greater than 80 percent of the PAL level. If not, today's rules also allow your reviewing authority to renew the PAL at a different level if it determines that level is more representative of baseline actual emissions. See section II.D.9, ''Should we require PALs to be adjusted at the time of PAL renewal,'' for more information on our rationale for allowing this discretion.

8. Are PALs Required to Expire?

In our 1998 NOA, we announced that we were considering, and requested comment on, an approach that would require PALs to expire after 10 years unless you choose to renew the PAL. We proposed that the PAL term would be 10 years. Several commenters agree with our suggested time frame of 10 years for the term of a PAL. Others support a 5-year period, which would fit with the title V permit review period. Some commenters support a period longer than 10 years.

Today, we are finalizing rules that require a PAL to be effective for a period of 10 years. We believe that a fixed-term PAL provides you with an appropriate time of regulatory certainty and allows a sufficient period of time for planning long-term capital improvements.

We also agree with those commenters who think it is beneficial to align the PAL renewal process with the title V permitting process for your major stationary source. Similar to a PAL permit process, the title V permit process provides the public with a comprehensive review of your source. We believe that aligning the PAL permit with the title V process will allow you and your reviewing authority to consolidate the administrative process for the two permitting actions. It also provides the public with a better understanding of your emissions characteristics relative to the surrounding community. However, we do not believe that requiring PALS to be reviewed every 5 years, consistent with the title V renewal period, provides industry with a sufficient period of regulatory certainty. We also believe that while the overall administrative burden for you and the reviewing authority is reduced if you are complying with a PAL, the establishment of a PAL requires an initial commitment of substantial resources. Given this initial resource investment, we do not believe that a 5-year fixed term for a PAL provides you or your reviewing authority with an adequate incentive to participate in the PAL system. Thus, in an effort to balance the need for regulatory certainty, the administrative burden, and a desire to align the PAL renewal with the title V permit renewal, we believe a fixed term of 10 years, the equivalent of two title V effective periods (10 years), is most appropriate. You may elect to renew your PAL after 10 years, for a subsequent 10-year period, rather than allow the PAL to expire.

In order to align the PAL renewal process with the title V permitting process, we suggest that you request that the reviewing authorities renew title V permits concurrent with issuance of the initial PAL permit, regardless of how many years are actually left on your title V permit.

9. Are PALs Required To Be Adjusted at the Time of PAL Renewal?

In 1996, we requested comment on ''why, how, and when a PAL should be lowered or increased without being subject to major NSR.'' In 1998, we announced that we were considering an option that required PALs to be renewed to reflect new current baseline actual emissions. We were also considering requiring a PAL to be adjusted for unused capacity. Under this approach, we would adjust a PAL downward when an emissions unit operates below the capacity level that was used to establish the PAL. In our 1998 NOA, we expressed three reasons why it might be appropriate to require PALs to be periodically adjusted. First, we expressed concern that the allowable-to-allowable applicability system of the PAL would allow you to indefinitely retain the right to pollute at an historical level of actual emissions. Second, we were concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in the area. And third, we were concerned that a PAL may interfere with a State's ability to plan for attainment if your actual emissions to the atmosphere are lower during a SIP planning year than in a subsequent year.

Some commenters generally oppose any periodic reviewing or adjustment of a PAL. They believe that such an approach would limit operational flexibility, discourage efficiency improvements, and create disincentives for voluntary reductions. However, other commenters generally support an approach that would require a periodic adjustment to PALs.

We continue to have concerns with an approach that would allow a PAL to be renewed without any evaluation of the appropriateness of the current PAL level. We believe such an approach would be contrary to the Act, and contrary to the court's decision in *WEPCO* v. *Reilly,* 893 F.2d 901, 908 (7th Circ. 1990). In WEPCO, the court determined that one statutory purpose of the NSR requirements is ''to stimulate the advancement of pollution control technology,'' and that ''allowing increased production (and pollution) through the extensive replacement of deteriorated generating system'' without triggering NSR review would create ''vistas of indefinite immunity from the provisions of * * * PSD.''

We believe today's rules avoid this inappropriate outcome, by requiring the reviewing authority to evaluate your baseline actual emissions at the time of PAL permit renewal.

Although we believe that a periodic review of the level of the PAL may be necessary, and that this may result in an adjustment in your PAL to a level that is representative of your baseline actual emissions, we do not believe that we should mandate an adjustment to the PAL based on only one prescribed methodology. Such an approach could lead to inappropriate results, as discussed below. Instead, we believe that our concerns can be appropriately addressed by providing the States the authority to adjust the PAL based on what is representative of your baseline actual emissions.

We believe that some discretion in determining what is representative of actual emissions is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits operating under a PAL provides, and discourages you from undertaking voluntary reductions. Accordingly, although today's final rules require the reviewing authority to consider the need for adjusting the PAL when your current baseline actual emissions plus the significant level are less than 80 percent of your PAL level, it also provides the reviewing authority discretion to consider a variety of factors in determining whether the PAL should be adjusted.

We are also providing your reviewing authority discretion to take into account measures necessary to prevent a violation of a NAAQS or PSD increment, and to prevent an adverse impact on an AQRV in a Federal Class I area. For example, although we remain concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in your area, we believe that managing an area's economic growth is the primary responsibility of the State. As such, the State, through your reviewing authority, should have discretion to manage the growth increment for your area. If your State wishes to encourage economic growth, then it may, at its discretion, reduce your PAL for that reason. Conversely, it may decide that encouraging economic growth is not a priority for the area and concurrently find no other concerns that warrant a downward adjustment in your PAL.

After further reflection, we also believe that it is inappropriate for us to mandate in all cases a prescribed methodology for adjusting PALs based on our concern that a PAL system may interfere with a State's ability to plan for attainment. We believe that the concern regarding planning for attainment is not unique to a PAL system. Most importantly, nothing in this rule reduces the State's discretion in developing plans to attain and maintain NAAQS. Under our major NSR applicability system, you could increase your emissions over your historical actual emissions by increasing utilization or hours of operation. If this occurs, there may be a discrepancy between the amount the State carries in the emissions inventory and the amount that you emit to the atmosphere. States should be cognizant of these issues and take appropriate measures in their SIP planning procedures to assure that emissions from any major stationary source, including a PAL participant, are properly characterized in the emissions inventory.

And finally, we agree with industry commenters that if we were to mandate an adjustment because your baseline actual emissions did not equal 100 percent of the PAL level, it would encourage you to increase production and emissions, and such an outcome would be counterproductive. We have accordingly provided your reviewing authority the ability to add a reasonable operating margin to your baseline actual emissions at the time of renewal. This operating margin was discussed previously in section II.D.7 above—''Should a PAL include a reasonable operating margin?''

10. Are Certain New Emissions Units That Are Added Under a PAL Required To Meet Some Level of Emissions Control?

We solicited comments on whether we should require you to control emissions from new emissions units that are added under an established PAL. Several commenters believe that BACT or LAER should not be required for these emissions units. A few commenters favor adding a requirement that BACT or LAER be required on new emissions units.

We believe that it is unnecessary to mandate a specific control level on new emissions units that you add under an established PAL. After reviewing the performance of a limited number of facilities that are participating in PAL pilot projects, we have concluded that these facilities' desire to maintain a large degree of operational flexibility under a PAL system has encouraged them to voluntarily install state-of-the-art controls on new emissions units. (See footnote 26 regarding our study, ''Evaluation of the Implementation Experience with Innovative Air Permits.'') We anticipate similar results as we extend the PAL program more broadly. Alternatively, we believe that you will add emissions controls to existing emissions units if this is a more cost effective approach to controlling your emissions. This is precisely the type of flexibility you should have for managing your total source-wide emissions under a PAL system. Furthermore, this cost effective approach was contemplated and supported by the statements of the court in *Alabama Power.* The court concluded that you should be allowed to add new emissions units if the new emissions from this unit could be ''set-off against decreases'' from other emissions units at the major stationary source. Accordingly, we do not believe that it is necessary to mandate the installation of emissions controls on new emissions units if you are able to continue to comply with your PAL even after installing the new emissions unit. If our projections on this matter prove to be incorrect in practice, we will consider revising our regulations in the future to require a specific control level on new and/or existing emissions units.

11. Under What Circumstances Are You Allowed To Increase Your PAL and How Are the Major NSR Requirements Applied To That Increase?

We proposed that whenever a PAL is increased due to the addition of a new unit, or due to a physical or operational change to an existing emissions unit, the units associated with the increase would be reviewed for current BACT or current LAER, air quality impacts modeling, and emissions offsets, if applicable. We noted that it may be difficult for a reviewing authority to determine which emissions units are associated with a physical change or change in method of operation when the emissions increase is the result of a source-wide production increase. We requested comment on five possible ways to apply the major NSR requirements when emissions increases are not directly associated with a particular change.

Commenters offered various suggestions for addressing emissions increases above the PAL. Several commenters believe that major NSR should only be applied to the emissions unit primarily responsible for the increase. Among the various commenters, there are a few supporters for each one of the options we proposed. In addition, one commenter suggests that we add *de minimis* increase levels; another suggests that we require offsets for each increase. Several industry commenters believe that we should not apply major NSR when an increase above the PAL is solely due to a production increase. One commenter believes all increases should be subject to BACT.

After considering the comments received, we agree with the commenters who believe that major NSR should only be applied to the emissions units (either new or modifications of existing units) primarily causing the increase. Accordingly, in the final regulations, we are confirming our proposed requirement that only those emissions units that are part of a PAL major modification would be subject to major NSR.

As discussed earlier, we believe that a PAL provides you with an incentive to control existing and new emissions units to maximize your operational flexibility under your PAL. We also recognize that there may be valid economic reasons for requesting an upward adjustment in a PAL. We are, however, concerned that if there were no restrictions on your ability to request a PAL increase, you would not have an incentive to control emissions. Therefore, under today's final rules, before the reviewing authority may approve a mid-term increase in your PAL, you must demonstrate that you are unable to maintain emissions below your current PAL even with a good faith effort to control emissions from existing emissions units. To make this demonstration, you must show that even if BACT equivalent control (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level) were to be applied to all of your significant and major emissions units, the resulting emissions level will exceed your current PAL when combined with the emissions from both your small emissions units and your new emissions unit's allowable emissions.

12. What Compliance Monitoring, Reporting, Recordkeeping, and Testing (MRRT) Requirements Are Necessary to Ensure the Enforceability of PALs as a Practical Matter?

The MRRT requirements for PALs are addressed below. Numerous commenters, generally State agencies and environmental groups, state that adequate monitoring, reporting, and recordkeeping requirements would be necessary to ensure that the PAL limits were enforceable. Some commenters hold that the monitoring, recordkeeping, and reporting provisions would be too burdensome and restrictive. Some believe that PALs would not be viable because of these requirements.

Several commenters request that we clarify the monitoring that is necessary to show compliance with a PAL, especially in relation to the CAM and title V programs. Several commenters prefer that the monitoring requirements be flexible and simple. These commenters urge us not to use CAM, require CEMS, or establish stringent protocols. A few commenters prefer that we not define what would be enforceable as a practical matter for PAL limits. Others insisted that the PAL limits must be federally enforceable.

We believe that the PAL must assure that the source maintains emissions below the PAL level to assure that major NSR does not apply. Therefore, we agree with the commenters who stated that adequate data collection requirements through means such as monitoring, reporting, and recordkeeping requirements are necessary to ensure that the PAL limits are enforceable as a practical matter. In fact, we find that not only monitoring, recordkeeping, and reporting requirements, but also emissions testing requirements, for emissions units subject to a PAL differ from other MRRT in one important aspect: actual unit emissions must be measured to provide a 12-month rolling total, and compared against a limit. Currently, many emissions units are required only to have MRRT suitable for initial or spot checks on emissions concentrations, not emissions quantification. Even emissions units whose MRRT meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), including those imposed by part 64 (the CAM rule), may need to be upgraded when those units are proposed to become subject to a PAL, because the approved title V MRRT may not be able to count emissions against a cap. While we believe you can obtain data for emissions quantification best through the use of CEMS or PEMS, in today's final rule we are allowing you to propose other types of emissions monitoring quantification systems, depending upon such factors as the size category of the emissions unit and its margin of compliance.

13. Is EPA Adopting an Approach That Allows Area-Wide PALs?

In 1996, we proposed an option that would allow a State to adopt an area-wide PAL approach. Under such an approach, all major stationary sources within a given geographic area would have a PAL. Our 1996 proposal contained little detail on how this would be implemented.

While a few commenters support area-wide PALs, many more oppose them. State agency commenters generally believe they would need time to develop PALs consistent with the approaches provided in the final NSR rule, as well as to develop data management and compliance assurance approaches that would accommodate the PAL approach. Thus, adding the area-wide PAL at the same time as the source-specific PAL may create several administrative headaches. Industry commenters maintain that area-wide PALs would ratchet down emissions and reduce flexibility.

We agree with the many commenters who opposed an area-wide PAL system, believing that the approach would be complex and resource and time intensive. We also perceived little interest in such an approach from the various stakeholders with whom we have met. Accordingly, we are not including any provisions in our final rules to implement an area-wide PAL system. However, we are not precluding such a program either. If a State currently has or wants to pursue an area-wide PAL program, then it must demonstrate that its program is equivalent to or more stringent than our final rules.

14. When Should Modeling or Other Types of Ambient Impact Assessments Be Required for Changes Occurring Under a PAL?

In our 1996 proposal, we requested comment on when modeling or other air quality impacts analysis is needed for changes occurring under a PAL to demonstrate protection of NAAQS, increments, and AQRVs.

One environmental commenter recommends modeling or other types of ambient impacts assessment whenever a change in emissions occurred under the PAL. One commenter recommends that FLMs be consulted whenever changes under the PAL are proposed, to determine whether an impact analysis for adverse impact on AQRVs would be necessary. Several commenters recommend modeling whenever a significant change occurred, but also recommend that EPA define significant change and how the modeling would be conducted. A facility could report the modeled effects of a minor change after the change is made (in a quarterly, semi-annual, or perhaps annual modeling summary), while more significant changes should be modeled prior to construction. The facility could be given a lot of responsibility in these cases and then held accountable (that is, required to mitigate) should an air quality increment or NAAQS be exceeded. These commenters also recommend that the impacts evaluation should be conducted at the time the PAL is established and that the PAL should clearly define what flexibility the source is allowed without further review and the types of changes for which additional review will be required. Some commenters generally believe that the proposed regulatory language concerning changes to PALs for air quality reasons was too vague and broad, but only a few of these commenters directly oppose modeling for changes under the PAL. One commenter states that if many changes were to require ambient air quality analysis, the PAL approach would have little if any benefit. The commenter believes that sources ought to discuss up front with permit authorities which emissions shifts might have consequences that would later require additional modeling/monitoring. If questions existed about certain emissions sources under a PAL, PALs could be approved with conditions assuring that certain post-approval modeling analysis be submitted.

In today's final rules, we believe we can rely on the reviewing authority's existing programs for addressing air quality issues. Certain changes in effective stack parameters under the PAL would generally be covered by the reviewing authority's minor NSR construction permit program. The reviewing authority would ordinarily request air quality modeling for any changes if it believes that the changes under the PAL may affect the NAAQS and PSD increments.

V. Clean Units

A. Introduction

In today's final rulemaking, we are promulgating a new type of applicability test for emissions units that are designated as Clean Units. This new applicability test will measure whether an emissions increase occurs, based on whether the physical change or change in the method of operation affects the Clean Unit status of the unit. This new applicability test provides that when you meet emission limitations based on installing state-of-the-art emissions control technologies (add-on control technology, pollution prevention techniques, or work practices) that are determined to be BACT or LAER, you may make any physical or operational changes to the Clean Unit without triggering major NSR, unless the change causes the need for a revision in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT, LAER, or Clean Unit determinations, or would alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. Emissions units that have not been through major NSR may also qualify for the Clean Unit applicability test if you demonstrate that their emission limitations based on their emissions control technology (that is, add-on control technology, pollution prevention technique, or work practice) is comparable to BACT or LAER and you demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. To be comparable to BACT/LAER, the controls must meet the specific comparability test that we describe in section V.C.3 of this preamble. That is, you must show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RACT/BACT/LAER Clearinghouse (RBLC); or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

The Clean Unit applicability test benefits the public and the environment by providing you with an incentive to install state-of-the-art emissions controls, even if you would not otherwise be required to control emissions to this level. You will benefit from these final rules because they provide you with increased operational flexibility. Once you have installed state-of-the-art emissions controls on an emissions unit and it is considered a Clean Unit, you may make changes to respond rapidly to market demands without having to obtain a preconstruction major NSR permit. Moreover, you and your reviewing authority will benefit from increased administrative efficiency. We believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. In such cases, the major NSR permitting requirements impose a paperwork burden with little to no additional environmental benefit. The Clean Unit applicability test eliminates this unnecessary administrative action.

B. Summary of 1996 Clean Unit Proposal

In the 1996 NSR Reform package, we proposed an innovative approach to NSR applicability called the Clean Unit Exclusion. The proposed Clean Unit Exclusion would allow you to modify qualifying emissions units without being subject to the NSR permitting process for a period of 10 years, as long as your maximum hourly emissions rates would not increase. We proposed that your pre-change hourly potential emissions rate must be established at any time up to 6 months prior to the proposed activity or project.

We proposed three methods by which an emissions unit could qualify for the Clean Unit Exclusion. One was that the emissions unit went through a major NSR action within the last 10 years and had an enforceable limit based on BACT or LAER. The second was if the emissions unit was permitted under a State or local agency minor NSR program within the last 10 years and the minor NSR control technology requirements were comparable to BACT or LAER. As part of this second method, we proposed that State and local agencies would submit their minor NSR programs for certification so that case-by-case determinations for emissions units permitted under a minor NSR program would not be necessary. The third method was a case-by-case determination that an emission limitation was comparable to BACT or LAER for that emissions unit. For these units, we proposed that the Clean Unit Exclusion would last for 5 years. We proposed that a determination that a limit was comparable to BACT or LAER could be based on one of two methods: (1) the average of the BACT or LAER for equivalent sources over a recent period of time (such as 3 years); or (2) the unit's control level is within some percentage (such as 5 or 10) of the most recent, or average of the most recent, BACT or LAER levels for equivalent or similar sources.

In addition, we asked for public comment on whether Clean Unit status should apply to emissions units with limits based on MACT or RACT. Although we did not propose accompanying regulatory language, we suggested that reviewing authorities use the title V permitting process to designate Clean Units.

C. Final Regulations for Clean Units

1. Summary of Final Action

Today's rule provides that your emissions unit qualifies as a Clean Unit, and qualifies to use the Clean Unit applicability test, if it has gone through a major NSR permitting review and is complying with BACT or LAER. Conversely, if your emissions unit has not gone through a major NSR permitting review, you do not automatically qualify for Clean Unit status. These emissions units must first go through a SIP-approved permitting process that includes a process for determining whether the emissions unit meets the criteria to be designated as a Clean Unit. This process must include public notice and opportunity for public comment.

To obtain Clean Unit status and qualify for the Clean Unit applicability test using a SIP-approved permitting process, you must pass a two-part test: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. You may make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is "substantially as effective" as BACT or LAER.

If your emissions unit automatically qualifies as a Clean Unit because it has been through major NSR permitting, you may use the Clean Unit applicability test for up to 10 years. Today's rules allow you to apply for Clean Unit status for control technologies you have installed in the past if you go through a SIP-approved permitting program that authorizes Clean Units and you qualify as a Clean Unit. The Clean Unit effective period for emissions units that must go through a SIP-approved permitting process to obtain Clean Unit status is consistent with the time frame for emissions units that automatically qualify as Clean Units. That is, you may only use the Clean Unit applicability test for a period of 10 years. If you meet the requirements that we describe in section V.C.9 of this preamble, you may re-qualify for Clean Unit status. Upon expiration of Clean Unit status, the Clean Unit applicability test no longer applies to changes at the emissions unit.

It is worth noting that in 1996, we proposed the provisions for Clean Units as a "Clean Unit Exclusion," although we discussed the provisions as a new applicability test. We received criticism from at least one commenter that our characterization of the test as an exclusion was inappropriate. We agree with this commenter, and have thus renamed the test as the Clean Unit applicability test. We believe that this title more appropriately reflects that the test is not whether you are excluded from review under major NSR, but whether using a more appropriate emissions test you trigger major NSR review.

2. Is Clean Unit Status Available in Both Attainment and Nonattainment Areas?

You may obtain Clean Unit status regardless of whether you are located in an attainment area or in a nonattainment area. Our proposed Clean Unit provisions were unclear on how emissions offsets and other nonattainment area requirements are affected by Clean Unit status. We want to clarify this issue. For sources in nonattainment areas which went through major NSR permitting while the area was nonattainment or which have qualified for Clean Unit status showing they are comparable to LAER, the permitted emissions level for the Clean Unit must have been offset. The emissions reductions resulting from installation of the control technology that is the basis of an emissions unit's status as a Clean Unit may not be used as offsets; however, emissions reductions below the level that qualified the unit as a Clean Unit may be used as offsets if they are surplus, quantifiable, permanent, and federally enforceable. Furthermore, for emissions units that are designated as Clean Units and that are located in nonattainment areas, RACT and any other requirements for nonattainment area sources under the SIP will still apply. The only exception to this is that the specific major NSR requirements related to calculating emissions increases from a physical change or change in the method of operation for all other existing sources that we describe in this preamble and codify in today's rules are not applicable to Clean Units, because the Clean Units are subject to an alternative major NSR applicability requirement for calculating emissions increases when changes are made.

As we discuss in detail in section V.C.3 of this preamble, the "substantially as effective" test for sources in nonattainment areas must consider only LAER determinations, except that emissions units in nonattainment areas that went through major NSR permitting while the area was designated an attainment area for that regulated NSR pollutant, and that received a permit based on a qualifying air pollution control technology, automatically qualify as Clean Units.

If your emissions unit received Clean Unit status while the unit was located in an attainment area and the area's attainment status subsequently changes to nonattainment, your emissions unit retains Clean Unit status until expiration. However, to re-qualify as a Clean Unit (see section V.C.9), the unit will have to meet the requirements that apply in nonattainment areas.

3. How Do You Qualify As A Clean Unit?

Any emissions unit permitted through major NSR automatically qualifies as a Clean Unit, provided the BACT/LAER determination results in some degree of emissions control. (We discuss the specific requirements for qualifying controls in section V.C.4 of this preamble.) These units already meet both the control technology and air quality criteria of the CAA and the NSR regulations. We believe that the emission limitations (based on the BACT/LAER determination) and other permit terms and conditions (such as any limits on hours of operation, raw materials, etc., that were used to determine BACT/LAER) are protective of air quality. Although emissions units that have been through major NSR automatically qualify for Clean Unit status, there are specific procedures for establishing and maintaining Clean Unit status. We discuss these procedures in detail in sections V.C.6 through 9 of this preamble.

Your emissions units that have not gone through a major NSR permitting action that resulted in a requirement to comply with BACT or LAER may qualify for Clean Unit status if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment. You must pass a two-part test to obtain Clean Unit status: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

You may show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

To make a demonstration using the first methodology in a nonattainment area, you must compare your control technology to the best-performing 5 similar sources in the RBLC for which LAER has been determined within the past 5 years. If the emission limitation that is achieved by your control technology is at least as stringent as any one of the 5 best-performing units, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that it qualifies as a Clean Unit. In attainment areas, you must compare your control technology to all BACT and LAER decisions that have been entered into the RBLC in the past 5 years, and for which it is technically feasible to apply the BACT or LAER control to your emissions unit type. If your control technology achieves a level of control that is equal to or better than the average of these determinations, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that your emissions unit qualifies as a Clean Unit.

After you have submitted your demonstration, the reviewing authority will also consider other BACT/LAER determinations that are not included in the RBLC to determine whether the proposed emissions rate is comparable to BACT/LAER, and incorporate this information into its determination as appropriate. In addition, the public will have an opportunity to review and comment on the reviewing authority's decision to designate an emissions unit as a Clean Unit. This approach ensures that you are meeting an emissions level comparable to that of BACT or LAER, while providing you flexibility to use the controls that are best suited to your processes.

We are providing this first methodology as a streamlined methodology for identifying Clean Units. Any unit that meets these qualifications shall be presumed to be a Clean Unit. Conversely, the opposite is not true. The reviewing authority shall not presume that a unit that does not meet the test is not a Clean Unit. The quality and number of determinations in the RBLC vary by different type of sources. The RBLC may not always identify all the types of control technology strategies that should qualify an emissions unit as a Clean Unit, or it may not provide a representative sample for making an appropriate determination. Therefore, even if you are unable to demonstrate that your emissions unit is a Clean Unit using this methodology, your reviewing authority shall not allow this outcome to prejudice its decision-making.

Accordingly, we are providing a second option for determining whether you qualify as a Clean Unit. If your emissions unit does not meet the emission limitation determined from the analysis of the RBLC described above (as appropriate for the area in which it is located), or if there is insufficient information in the RBLC to conduct the analysis, then you may still show, on a case-by-case basis, that your emissions unit will achieve a level of control that is ''substantially as effective'' as BACT or LAER, depending whether your emissions unit is in an attainment area or a nonattainment area. In an attainment area, your emissions unit must achieve a level of control that is ''substantially as effective'' as BACT. In a nonattainment area, your emissions unit must achieve a level of control that is ''substantially as effective'' as LAER. The reviewing authority will make a decision on whether a particular air pollution control technology (which includes pollution prevention or work practices) is ''substantially as effective'' as the BACT/LAER technology for a specific source on a case-by-case basis.

We are not promulgating specific requirements or performance criteria for satisfying the ''substantially as effective'' test, because we believe reviewing authorities are in the best position to determine whether in fact a particular air pollution control technology (which includes pollution prevention or work practices) is ''substantially as effective'' as the BACT/LAER technology for a specific source. The case-by-case determinations must meet the same air quality test as those units going through a BACT/LAER determination. Moreover, the public has opportunity for public review and comment on the ''substantially as effective'' decision. With these safeguards, we believe the ''substantially as effective'' test will ensure determinations that meet both the control technology and air quality tests, as well as allow sources to implement the controls that are best suited to their individual processes.

Under the second part of the test to determine whether your unit qualifies for Clean Unit status, you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset.

4. Can an Emissions Unit That Applies No Emissions Control Technology Qualify as a Clean Unit?

In most cases, BACT/LAER will result in significant emissions decreases (such as 90 percent control for many VOC coating sources).[32] In some circumstances, however, the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using a control technology (add-on control, pollution prevention technique, or work practice). Under today's rules, you will not qualify as a Clean Unit in such circumstances. More specifically, today's rules also require you to make an investment to qualify initially as a Clean Unit. An investment includes any cost which would ordinarily qualify as a capital expense under the Internal Revenue Service's filing guidelines whether or not you actually choose to capitalize that cost. An investment also includes any cost you incur to change your emissions unit or process to implement a pollution prevention approach, including research expenses, or costs to retool or reformulate your emissions unit or process to accommodate an add-on control, pollution prevention approach, or work practice.

5. When Do the Major NSR Requirements Apply to Clean Units?

Once an emissions unit qualifies as a Clean Unit, it is subject to an alternative major NSR applicability test for calculating emissions increases for subsequent changes. As we discussed in section II of this preamble, we have codified our longstanding policy (for emissions units that are not Clean Units) that a major modification occurs if both of the following result from the modification: (1) A significant emissions increase following the physical or operational change; and (2) a significant net emissions increase from the major stationary source. The major NSR applicability test for Clean Units is a different process.

For Clean Units, you must first determine whether a project causes the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. If it does, you lose Clean Unit status, and the project is subject to the applicability requirements as if the emissions unit were never a Clean Unit. If the project does not cause the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit, then you maintain Clean Unit status, and no emissions increase is deemed to occur from the project for the purposes of major NSR. Once you have lost Clean Unit status, you can only re-qualify for Clean Unit status by going through the process that we describe in section V.C.9 of this preamble.

6. Can You Get Clean Unit Status for Controls That Have Already Been Installed?

As discussed in section V.C.3, emissions units that have been through major NSR permitting automatically qualify for Clean Unit status. This includes those emissions units that went through major NSR before promulgation of today's final rules. If an emissions unit automatically qualifies for Clean Unit status because it went through major NSR, its Clean Unit status is based on the BACT/LAER controls that went into service as a result of the major NSR review. That is, Clean Unit status is based on the BACT/LAER controls regardless of whether the actual process for designating Clean Unit status through title V occurs at some time after the controls went into service. However, Clean Unit status, and the ability to use the applicability process for Clean Units, does not begin until the Clean Unit effective date. We discuss the specific procedures for when Clean Unit status starts, when it ends, and how it is designated in sections V.C.7 through 9.

For emissions units that have not been through major NSR, our rules allow your reviewing authority to provide you with Clean Unit status for emissions control that you have already installed and operated. However, our final rules also limit the time frame under which your reviewing authority is allowed to make such determinations for Clean Unit status that is granted through a SIP-approved permitting process other than major NSR. Your reviewing authority will only be able to grant Clean Unit status for previously installed emissions controls if they were installed before the effective date of the program in your area. If the emissions unit's control technology is installed on or after the date that provisions for the Clean Unit applicability test are effective in your area, you must apply for Clean Unit status from your reviewing authority at the time the control technology is installed. As for emissions units that went through major NSR review, Clean Unit status for emissions units permitted through SIP-approved programs other than major NSR does not begin until the Clean Unit effective date.

If you are applying for retroactive Clean Unit status, today's final rules allow your reviewing authority to compare your emissions control level to the BACT or LAER level that would have applied at the time you began construction of your emissions unit. However, in some cases, such a comparability analysis may be difficult for you to demonstrate because of lack of sufficient information from which your reviewing authority can make a reasoned determination. If this is the case, then you will have to demonstrate that your emissions controls are comparable to a BACT or LAER limit from a subsequent or current date.

7. When Can I Begin To Use the Clean Unit Test?

The exact effective date depends on the circumstances of the individual emissions unit, as explained further below. As a general principle, however, the effective date for Clean Unit status can never be before the Clean Unit provision becomes effective in the relevant jurisdiction.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, the effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier. However, the effective date can be no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the SIP and become effective for the State in which the unit is located. That is, if the source had a major NSR permit and began operating before the Clean Unit provision becomes effective in the relevant jurisdiction, the effective date is the date the State or local agency begins authorizing Clean Unit status. As we noted earlier, if the emissions unit previously went through major NSR, it automatically qualifies as a Clean Unit. The original Clean Unit status would be based on the controls

[32] It is possible that a BACT/LAER analysis will not always result in the requirement of add-on controls at a source. In some situations, a reviewing authority may appropriately determine that the control technology that best represents BACT/LAER is a work practice, or a combination of work practices and add-on controls. As a result, a requirement to use work practices, or a combination of add-on controls and work practices, as an emissions control technology, could qualify an emissions unit for Clean Unit status, provided it meets the criteria established.

that were installed to meet major NSR. An additional investment at the time the original Clean Unit status becomes effective is not required.

For emissions units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, the effective date is the date the new major NSR permit is issued.

If you obtain Clean Unit status from your State or local reviewing authority using a SIP-approved permitting process other than major NSR, the Clean Unit effective date is the later of the following dates: (1) The date that the State or local agency permit that designates the emissions unit as a Clean Unit is issued; and (2) the date that the emissions unit's air pollution control measures went into service. That is, if the controls went into service before the issuance date of the State or local agency permit that designates the unit as a Clean Unit, the Clean Unit effective date is the date that the permit is issued. As with units that have been through major NSR, additional investment is not required for the limited cases where there is a retroactive designation. If the issuance date of the State or local agency permit that designates the emissions unit as a Clean Unit is before the date the controls went into service (as would likely be the case for a unit that is new or modified after the State or local agency begins to authorize Clean Unit status), then the effective date of Clean Unit status is the date the controls went into service.

8. How Long Does Clean Unit Status Last?

In most cases, you may use the Clean Unit applicability test for a period of 10 years.[33] As a general principle, the Clean Unit expiration date can never be later than the date that is 10 years after the controls are brought into service.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier. However, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

For emissions units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date. However, as noted above, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

The expiration date for Clean Units that have not been through major NSR permitting depends on whether the owner or operator qualifies for Clean Unit status based on current BACT/LAER, or on BACT/LAER at the time the control technology was installed. If the owner or operator of a previously installed unit demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT/LAER requirements that applied at the time the control technology was installed, then Clean Unit status expires 10 years from the date that the control technology was installed. For all other emissions units (that is, previously installed units that are demonstrated to be comparable to current BACT/LAER, new units, and units that re-qualify as Clean Units), Clean Unit status expires 10 years from the effective date of the Clean Unit status. In addition, for all emissions units, Clean Unit status expires any time the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

When your Clean Unit status expires, you are subject to the major NSR applicability test as if your emissions unit is not a Clean Unit. The permitted emissions levels established for the Clean Unit do not expire.

9. Can I Re-qualify for Clean Unit Status?

You may re-qualify for Clean Unit status after the status has expired or you have otherwise lost Clean Unit status, if you meet the conditions in our final regulations. As we stated before, we believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. Also, the period for which any specific air pollution control technology (which includes pollution prevention or work practices) will continue to achieve the same level of control depends on many factors. As a practical matter, we have established a single time frame of 10 years for Clean Unit status, to provide simplicity in our final rules. However, for reasons we discuss in detail in section V.E.1 of this preamble, we determined that a reasonable average equipment life for a control technology is generally longer than 10 years. Certainly we want to encourage source owner/operators to install and maintain state-of-the-art control. We believe this is more likely when you can be assured that you can retain Clean Unit status for the useful life of the equipment, as long as air quality continues to be assured. The useful life of the equipment may extend beyond the original Clean Unit expiration date. Therefore, we are promulgating final regulations that allow you to apply to re-qualify for Clean Unit status.

To re-qualify for Clean Unit status, you would generally follow the same process that you used in first qualifying for Clean Unit status. However, we will not necessarily require you to meet an additional investment test to re-qualify for Clean Unit status for the same controls. That is, unless the controls used to establish Clean Unit status are no longer BACT/LAER or comparable, there will be no requirement for an investment to re-qualify for Clean Unit status.

You may re-qualify for Clean Unit status either by going through major NSR or by going through the alternative Clean Unit Test that we described in section V.C.3 of this preamble: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. Regardless of which process you used to establish Clean Unit status initially, you may choose to re-qualify for Clean Unit status by going through major NSR or by going through the alternative two-part test.

Once you have submitted an application to re-qualify for Clean Unit status, the reviewing authority will make a determination concerning current BACT/LAER or comparable control technology. For example, suppose you had Clean Unit status for an emissions unit for which the controls

[33] As discussed in section III.E of today's preamble, we believe that 15 years represents a reasonable time period for designating a Clean Unit. However, we proposed and took comment on a 10-year period; therefore, we are finalizing today's rule with a 10-year duration. In a separate **Federal Register** notice we will be proposing to change this duration to 15 years.

went into service June 1, 1996, the permit application for Clean Unit re-qualification was submitted December 1, 2004, and the Clean Unit status expires June 1, 2006. In cases where the controls you installed in 1996 are still BACT/LAER or comparable when the reviewing authority makes the determination following your application submittal in 2004, the emissions unit can re-qualify for Clean Unit status based on the controls installed in 1996 if your emissions unit still meets all of the criteria for Clean Unit status. That is, in addition to the control technology review, the emissions unit must go through an air quality review and public participation.

A safeguard related to Clean Unit controls is that for re-qualifying for Clean Unit status when the emissions unit is located in a nonattainment area, the control determination must be LAER or comparable to LAER. If you previously received Clean Unit status based on the BACT level of control while the source was located in an attainment area and the attainment area becomes a nonattainment area by the time your Clean Unit status expires, the Clean Unit status for re-qualification must be based on controls that are LAER or comparable to LAER.

The air quality analysis for Clean Unit re-qualifications will be that of the path that you have chosen'major NSR, or comparable. As we discuss in detail in section V.C.3 of this preamble, for emissions units qualifying for Clean Unit status through the comparable test, you must show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We believe that the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process will ensure that Clean Units will continue to protect air quality throughout the 10-year re-qualification period. Moreover, any offset or mitigation requirements as a result of a previous major NSR determination will remain in force.

We expect that in many cases the controls used to initially establish Clean Unit status will still be operating efficiently and the Clean Unit status can be reestablished for an additional 10 years based on those controls. Suppose, however, you submitted an application to re-qualify for Clean Unit status and the reviewing authority determines that your existing controls do not meet the level of current BACT/LAER or comparable controls. In this case, you must install new or upgraded controls to re-qualify for Clean Unit status. You must go through the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process as described above.

10. What Terms and Conditions Must the Permit for my Clean Unit Contain?

Major NSR permits contain the emission limitations based on BACT/LAER, other permit terms and conditions that the reviewing authority identifies as representative of BACT/LAER (such as limits on hours of operation), and monitoring, recordkeeping and reporting requirements for the emissions unit. If you are qualifying for Clean Unit status through the major NSR review, your major NSR permit will have such terms and conditions. Likewise, any permit under a SIP-approved permitting process other than major NSR that designates an emissions unit as a Clean Unit must specify: (1) The source-specific allowable permit emission limitations, the exceedance of which, in combination with a significant net emissions increase, will trigger major NSR review; (2) other permit terms and conditions that the reviewing authority identifies as representative or comparable to BACT/LAER for your control technology (such as limits on operating parameters, etc.); (3) any conditions used as the basis for the control technology determinations (hours of operation, limits on raw materials, etc.); and (4) the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a ''clean'' level of emissions control is being achieved. Additional monitoring, recordkeeping, and reporting may be required to assure compliance under §§ 70.6(a)(3) or 70.6(c)(1) (that is, to assure compliance under title V).

The State and local agency permits establishing Clean Unit status must contain a statement designating the emissions unit as a Clean Unit. The State or local agency permit must also include general terms and conditions indicating the Clean Unit effective date and expiration date. Suppose the State or local agency permit has an effective date of May 5, 2006, and the controls will be installed after this date. The SIP permit would state that the effective date of the Clean Unit status is the date the controls go into service. The permit would also state that Clean Unit status will expire no later than May 5, 2016.

Your title V permit must include the Clean Unit status, as well as the effective and expiration dates of the Clean Unit status. Your title V permit must also include: the emission limitation(s) that reflect BACT/LAER or comparable control; other permit terms and conditions that the reviewing authority has determined represent BACT/LAER or comparable control (such as limits on hours of operation) and that ensure that air quality is protected; and the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a ''clean'' level of emissions control is being achieved.

11. How Will my Clean Unit Status be Incorporated Into my Title V Permit?

Clean Unit status and other permit terms and conditions must be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71, but no later than when the title V permit is renewed.

The title V permit must also contain the specific dates on which your Clean Unit status is effective and on which it expires. We are aware that the specific Clean Unit effective and expiration dates will frequently not be determined at the time that Clean Unit status is established. Therefore, the initial title V permit action that incorporates Clean Unit status and other permit terms and conditions may need to state the Clean Unit effective and expiration dates in general terms. For example, for units that have been through major NSR, the initial title V permit might state that the expiration date is the earlier of the following dates: the date 10 years after (1) the Clean Unit's effective date, or (2) the date the equipment went into service. The permit does not have to include the specific Clean Unit effective and expiration dates where they cannot be determined at the time of initial incorporation, such as would be the case when the Clean Unit has yet to be constructed. Furthermore, in these instances, we are not requiring that the title V permit be modified to incorporate the specific Clean Unit effective and expiration dates until the next permit renewal, reopening, or modification after such dates are known.

As soon as the specific Clean Unit effective and expiration dates are known, the source must report them to the reviewing authority. The specific Clean Unit effective and expiration dates must then be incorporated into the title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal. However, it is not necessary to amend the SIP-approved permit to incorporate the specific Clean Unit effective and expiration dates, as long as these dates are incorporated into the title V permit at the next renewal. If you wish to incorporate the Clean Unit effective and expiration dates into the SIP permit, a title V modification would be required.

While the title V permit contains the Clean Unit permit terms and conditions, we want to emphasize that any changes to Clean Unit permit terms and conditions (other than incorporating the specific Clean Unit effective and expiration dates) must first be made through a SIP-approved permitting process that provides for public review and opportunity for comment. Any such changes would be incorporated into the title V permit in the manner described above.

12. Can a Clean Unit Be Used in a Netting Analysis?

Generally, for an emissions unit that has Clean Unit status because it has gone through major NSR permitting, you must not include emissions changes at the Clean Unit in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of Clean Unit status or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for the purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets. We are allowing the credit to be computed in this manner because the owner or operator has already obtained an actual emissions-based offset for the emissions up to the Clean Unit emission limitations. By the owner/operator's accepting a federally enforceable emission limitation below this level, these offsets are now available to create additional actual emissions reductions.

The final rules are similar for emissions units that are designated as Clean Units in a SIP-approved permitting process other than major NSR. You must not include emissions changes that occur at such units in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of the SIP requirements adopted to implement the Clean Units or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets.

13. How Does Clean Unit Status Apply When There Are Multiple Pollutants?

Clean Unit status is pollutant-specific and may not be granted for more than one pollutant, except in cases where a group of pollutants is characterized as a single pollutant, such as VOCs. You may, however, qualify for simultaneous Clean Unit status for other pollutants at those emissions units that are sufficiently controlled to independently qualify as ''clean'' for each pollutant. For units applying for Clean Unit status and that do not already have a major NSR permit, the reviewing authority must specify the pollutants for which Clean Unit status applies as part of the permitting process establishing Clean Unit status.

D. Legal Basis for the Clean Unit Test

As discussed above, the Clean Unit applicability test would provide an alternative emissions test for determining if a significant increase in emissions has occurred after a physical change or change in the method of operation at units that are designated as ''clean.'' We believe that we have the authority to allow these specific types of units to use a different applicability test.

The CAA is silent on whether increases in emissions for purposes of determining whether a physical or operational change constitutes a modification must be measured in terms of actual emissions, potential emissions, or some other currency. We believe that it is a reasonable interpretation of the CAA to determine applicability of the major NSR program for units qualifying as Clean Units in terms of the emission limitations or work practice requirements in the permit, and that this interpretation is consistent with the statutory purposes of NSR.

The PSD permitting program has 5 key elements: (1) Control technology review; (2) air quality review; (3) monitoring requirements; (4) information on the source; and (5) procedures for processing applications, including public notice and the opportunity for comment. A new major source or major modification in an attainment area must go through PSD permitting to become a Clean Unit. That process would have had to include the elements listed above. CAA section 165.

Similarly, the CAA requires new major sources or major modifications undertaken in nonattainment areas to obtain permits that require them to meet LAER and to obtain offsetting emissions reductions. CAA section 173. In order to be designated a Clean Unit, a major source or modification in a nonattainment area would have had to have gone through major NSR permitting review in the last 10 years.

We believe that units that have undergone minor source permitting in a manner that fulfills the statutory purposes of major NSR—either because a State's minor NSR program already contains equivalent provisions or because the existing program is enhanced for the purpose of allowing the reviewing authority to satisfy Clean Unit criteria—also will have satisfied the requirements of the CAA in a manner sufficient to justify Clean Unit status. As we have discussed in section V.C of this preamble, to obtain Clean Unit status through a minor NSR program, that process must include a requirement for public participation. Furthermore, emissions units that are designated as Clean Units through SIP-approved minor NSR programs must satisfy an air quality test. You must provide information demonstrating that you will not cause or contribute to a NAAQS or PSD increment violation or adverse impact on an AQRV in a Federal Class I area. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset, or the reviewing authority will have to show that these emissions will not interfere with the State's ability to achieve attainment.

For Clean Units that have emission limitations and/or work practice requirements established through programs that fulfill relevant major NSR statutory requirements, we believe that the alternative way to estimate emissions increases to evaluate applicability set forth under the Clean Unit Test is appropriate and consistent with Congress's intent. A project at a Clean Unit that would require a revision to the emission limitations or work practice requirements established through permitting programs that meet the requirements of the Act, or that would alter any physical or operational characteristics that formed the basis for the permitting action, must go through a new permitting process. The reviewing authority must have already required state-of-the-art pollution control technology (or, through an investment, its pollution prevention or work practice equivalent), conducted the required air quality analyses based on the emissions level in the permit, and provided the public with an appropriate opportunity to comment on that level of emissions and air quality impact. Therefore, we believe that allowing an alternative means of evaluating applicability based on a revised emissions test for this category of unit is consistent with the CAA.

E. Summary of Major Comments and Responses

Although a few commenters categorically oppose the Clean Unit Test, most commenters support the concept. Practically all commenters oppose some aspect of the test or request that the test be clarified. Below are the major comments and our responses.

1. How Long Should You Be Eligible for the Clean Unit Applicability Test?

We received numerous comments on the duration of Clean Unit status. In the proposal, we suggested a 10-year duration and asked for comments regarding this period. We received comments supporting various lengths of time from 2 to 20 years. Although some commenters support a 10-year duration, other commenters oppose it.

Many commenters believe that 10 years is too short for Clean Unit status. These commenters argue that BACT/LAER technologies accomplish substantial pollutant removals, and that the cost of a slight increase in pollutant removal is usually significant. These commenters urge us to establish a Clean Unit status duration that comports with the useful life of the control equipment, which would enable you to recover the costs of installing the pollution control technology. They believe that you should be able to recoup the investments in pollution control before being forced to abandon that technology and pay again for newer technology. Some commenters request that a presumptive life of 20 years be awarded to Clean Units, which is approximately how long the control equipment should be effective.

Some commenters believe that 10 years would be too long, because they believe that advances in control technology occur more rapidly. A 10-year duration would allow old, less effective technologies to be the basis of immunity from the NSR program. These commenters are particularly concerned about the 10-year duration for BACT/LAER determinations that were based on no controls.

We believe that we have discretion to determine the appropriate period for which you should be eligible for the Clean Unit applicability test. As a policy matter, we believe that this time period should reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. As a practical matter, we realize that the ''ideal'' time frame will vary by emissions control technology and by pollutant; however, we believe using a single time frame will provide simplicity in our final rules.

To determine an average life expectancy for a variety of control technologies, we relied on the guidelines for equipment life for 9 commonly used emissions control technologies published in ''Estimating Costs of Air Pollution Control Systems, Part II, Factors for Estimating Capital and Operating Costs.''[34] Using the average of the low, average, and high values, we determined that a reasonable average equipment life for a control technology is equal to 15 years.

We then looked at the incremental improvement in control technology over time. We found that the evolution of pollution control equipment over time is dominated by innovation, rather than invention. In other words, the change in design and capacity for any given device type occurs infrequently as a series of marginal improvements over the preceding design. Consequently, the marginal improvement in pollution abatement one can expect between generations of the same type of device is also very small—too small to justify the cost of an entirely new unit. For example, flue gas desulfurization (FGD) units have been used in the United States for about 20 years, and were used in Japan and Germany for 10 years before that. During the early 1980's, a typical FGD system removed about 90 percent of the sulfur from a flue gas stream. Today, modern FGD systems typically average 95 to 99 percent removal efficiency—less than a 10 percent improvement in 20 years.

We also evaluated, from a cost-per-ton basis, whether the marginal improvement in removal efficiency is too expensive. Again, we considered the FGD example. From an actual NSR determination for a coal-fired electrical generating unit in the Midwest, the installation of an FGD system in 1985 would have cost $189 million and had a removal efficiency of 90 percent (76,500 tons of sulfur per year). The identical boiler in 2001 would use an FGD system with a 95 percent efficiency, costing $285 million, and removing 80,750 tpy, an additional 4,250 tons. The additional cost for the improved design for the 2001 installation (including the retrofit and upgrade of existing components and the new cost of larger pumps and other auxiliary equipment) would have been more than $100 million, or greater than $24,000 per ton. Consequently, from an efficiency standpoint, requiring an upgrade on this unit to BACT or LAER levels would not have been economical.

After reviewing all of this information, we determined that a 15-year period represents a reasonable and appropriate time frame during which you should be allowed to use your permitted allowable emissions to determine whether an increase triggers major NSR review. However, we proposed and took comment on a 10-year duration. Therefore, today we are finalizing a single time frame of 10 years that applies to all types of emissions control technologies and all types of pollutants. Because we believe that 15 years represents a reasonable time frame, we will be proposing a 15-year duration for Clean Unit status. After considering any public comments on a 15-year duration for Clean Unit status, we may amend today's final regulations.

We believe it is beneficial to allow emissions units using pollution prevention techniques or work practices to qualify for Clean Unit status where those units meet certain criteria. In some cases (coating operations, for example), pollution prevention techniques or work practices are state-of-the-art pollution control, and either

[34] Vatavuk, William, ''Part II, Factors for Estimating Capital and Operating Costs,'' *Chemical Engineering,* Nov. 3, 1980.

there would not be an improvement in pollution control if the unit were required to install add-on controls or the incremental cost effectiveness of the add-on control installation would be too high for it to qualify as BACT. In other cases, the most stringent control is based on add-on control and pollution prevention. Therefore, under many circumstances, we believe that pollution prevention techniques and work practices can be implemented to achieve a level of emissions reductions comparable to that achieved by BACT/LAER add-on controls. Also, initiation of a pollution prevention technique or a work practice can require a substantial investment in research to retool or reformulate your operations. Thus, we do not believe that a blanket exclusion from Clean Unit status is appropriate for emissions units that are controlled with pollution control techniques.

Implementation of pollution prevention approaches and work practices usually requires research, followed by some retooling or reformulation of a process line or unit operation. As part of this retooling or reformulation, some equipment has to be purchased up front (for example, sniffers for leak detection and repair operations, improved process control consoles and/or software for recycle streams, initial modeling for combustion optimization systems). This equipment purchase or initial modeling involves a one-time investment; hence, there is an investment associated with pollution prevention or work practice implementation. Researching the application of an approach also qualifies as an investment for these purposes.

We received comment from a number of commenters who are concerned about Clean Unit status when BACT/LAER determinations are based on no control. As these commenters note, ''no controls'' does not equate to a well-controlled emissions unit. We agree with these commenters, and today's final rules clarify that Clean Unit status can be based on add-on control, pollution prevention techniques, work practices, or a combination of them. We recognize that there are some circumstances when the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using an air pollution control technology (which includes pollution prevention or work practices). We believe that such emissions units should not qualify as Clean Units, because they fail the very premise under which we established the Clean Unit applicability test. That is, there is no period of time in which we can reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. Source categories that currently have few or no control technology options are likely to be the categories that will experience a rapid advancement in emissions control technology over a short period of time. Accordingly, today's final rules contain two limitations on use of the Clean Unit applicability test. You may not use the Clean Unit applicability test for any emissions unit that is not using an air pollution control technology (which includes pollution prevention or work practices) and for which you have not made an investment to control emissions.

2. Does the Clean Unit Applicability Test Measure the Increase in Maximum Hourly Potential Emissions?

We proposed that the Clean Unit Test would continue to apply as long as the emissions unit's maximum hourly potential emissions did not increase. The baseline for the maximum hourly potential emissions rate could be established at any time in the 6 months before the activity or project that increases emissions. Almost all commenters oppose basing the Clean Unit Test on the hourly PTE, as well as the 6-month period for setting the emissions rate. Some commenters argue that an hourly PTE test is not environmentally protective enough. One commenter notes that we were inappropriately using the applicability test under the NSPS as the applicability test for major NSR, which should be based on tpy. Many commenters view the hourly PTE test as so restrictive that few sources would take advantage of the Clean Unit Test. These commenters believe that the hourly emissions rate obscures the real basis for Clean Unit status, which is the add-on control efficiency.

We agree with the commenters who maintain that Clean Unit status should be based on the emissions level achievable through the use of control technologies. As these commenters note, once an emissions level has been determined based on BACT/LAER, it is unlikely that additional review would result in a more stringent level of control. As a result, we are not finalizing the Clean Unit Test as proposed with the hourly PTE test. Instead, today's final rules for Clean Units are based on reduction of air pollution through the use of control technology (which includes pollution prevention or work practices) that meet both the following requirements. First, the control technology achieves a BACT/LAER level of emissions reduction as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for Clean Unit status if the BACT/LAER determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type. Second, the owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

By adopting this approach, we are allowing the reviewing authority to decide the appropriate emission limitations or work practice requirements that will be used to obtain and maintain Clean Unit status. If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements that form the basis for Clean Unit status, the emissions unit remains a Clean Unit. On the other hand, if the project causes the need for such change to the emission limitations or work practice requirements, the emissions unit loses Clean Unit status and is subject to the applicability requirements of major NSR.

3. What Kind of Changes Are Allowed Under Clean Unit Status?

It is not our intention to limit increases in emissions unit capacity as long as emissions are under the source-specific allowable levels and the increase is within the capacity for which you obtained approval when applying for Clean Unit status. Incremental improvements to existing units are acceptable. However, complete changes to emissions units making them into completely different units than were originally permitted are not acceptable. For example, switching to a smaller but more polluting process than originally permitted may trigger stricter BACT/LAER requirements, even at the same annual emissions rate, since higher percentage removal rates and lower costs would be possible at higher concentrations.

We expect that changes such as, but not limited to, increasing production to permitted levels, reconfiguring the process, changing process chemicals if consistent with the original Clean Unit application, replacing components, replacing catalysts, or adding other controls, or other changes would be allowable for Clean Units. In no instances are we authorizing violations of any existing permit conditions or other applicable requirements that may apply to the Clean Unit. You may not reconstruct a Clean Unit under an existing Clean Unit status.

4. Does the Clean Unit Applicability Test Apply to Units That Have Not Gone Through a Major NSR Permitting Review?

In 1996, we proposed that reviewing authorities submit their minor source permit decisions for us to determine whether the emission limitations were comparable to BACT or LAER. Commenters generally support allowing units permitted through minor NSR programs to qualify for Clean Unit status. These commenters believe State and local agencies are well-equipped to make control technology determinations. A few commenters are concerned that control technology determinations made under minor NSR programs do not always require adequate air quality review or opportunity for public comment and review. They maintain that these program elements are essential for making control technology determinations that are equivalent to BACT/LAER.

We also received comments on allowing Clean Unit status for emissions units that have not gone through either major or minor NSR, such as those that decrease emissions to meet other requirements under the Act. These comments are mixed. A few commenters support this option. Others believe it makes no sense to extend the status to units that had not had a recent control technology determination, particularly considering the burden the review would place on reviewing authorities.

We agree that control technology determinations made by State and local agencies can be comparable to BACT/LAER, regardless of the purpose for which the control technology decision is made. However, we also agree with those commenters who believe a thorough analysis is necessary to ensure that air quality is protected. Moreover, we agree that a control technology determination is incomplete unless it has been through public review.

Therefore, today we are promulgating regulations that allow emissions units that have not had a BACT/LAER determination to qualify for Clean Unit status, if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment to determine whether you should qualify as a Clean Unit.

5. Does Clean Unit Status Apply to Units That Have RACT or MACT Limits?

A number of commenters maintain that emission limitations based on RACT and MACT achieve control comparable to those based on BACT and LAER. These commenters therefore believe Clean Unit status should be available for emissions units with RACT or MACT limits. However, other commenters agree with us that RACT and MACT limits should not automatically be considered equivalent to BACT/LAER limits.

We are maintaining our position in the proposal rule that Clean Unit status does not presumptively apply to units with limits based on RACT or MACT. However, when you believe a specific RACT or MACT limit is comparable to BACT/LAER, you may choose to use a SIP-approved permitting process to try to obtain Clean Unit status.

6. How Should We Determine Whether a Control Technology Is Comparable to BACT or LAER?

We proposed two methods for determining that control technology was comparable to BACT/LAER—average of the level of control for the last 3 years, and percent control. None of the commenters support using the average emissions rates to determine comparability. The commenters believe that in some cases this approach could lead to skewed results, or that the average control determination can differ substantially from the most recent determination. The commenters suggested that EPA consider all technologies required to be considered in a BACT/LAER determination, not just those listed in the RBLC. The commenters also say that it is not acceptable to call an uncontrolled unit a ''clean'' unit, when the Clean Unit Test is meant for companies that have taken the effort and expense to install controls or low emitting equipment. Although a few commenters support using percent control, several commenters oppose it. They maintain that defining control levels based on a certain percentage derived from BACT or LAER for equivalent sources is not simple and would require the frequent collection and maintenance of large quantities of information.

Based on the public comments on our two proposed methods, we have decided to develop a modified version of the proposed averaging method for determining when an air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER. You can make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) by comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

Under the first approach, we have developed slightly different approaches for sources located in attainment and nonattainment areas. For those emissions units located in attainment areas, the emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. To address the commenters' concerns regarding other BACT/LAER determinations that might not be in the RBLC, we have included a provision that allows the reviewing authority to also compare this presumption to any additional BACT or LAER determinations of which it is aware, and to consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

For sources in nonattainment areas, the emissions unit's control technology is presumed to be comparable to LAER if it achieves an emission limitation that is at least as stringent as any one of the 5 best-performing similar sources for which a LAER determination has been made within the preceding 5 years, and for which information has been entered into the RBLC. As is the case for units in attainment areas, the reviewing authority shall also compare this presumption to any additional LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to LAER is correct.

The second approach, the ''substantially as effective'' test, avoids a ''one-size-fits-all'' approach that could preclude some well-controlled sources from benefitting from the Clean Unit Test simply because there is insufficient information in the RBLC or because they are using an innovative approach to emissions control. This provision will allow you to use alternative controls as long as they achieve comparable control and air quality results. We believe that the reviewing authority is in the best position to judge whether a particular control technology achieves an emissions control level that is comparable to BACT or LAER for a specific application, as well as to assure that air quality impacts have been accounted for. Thus, rather than requiring the reviewing authority to submit its permit decisions to us for approval as a comparable technology, our final rules allow the reviewing authority the ability to make this determination after the public comment process.

7. Can Clean Unit Status Be Made Using the Title V Permitting Process?

We proposed that for sources that had not undergone major NSR, Clean Unit status would occur as part of the title V permitting process. Although a few commenters support this concept, several State and local agency commenters strongly disagree. These commenters believe that title V is an appropriate mechanism for documenting Clean Units, but that the process for certifying sources should be separate from title V to avoid delays in title V permitting.

We agree with these commenters, and today are promulgating provisions that an emissions unit may be designated as a Clean Unit once it has gone through major NSR or another SIP-approved permitting program that provides for public notice and opportunity for comment. This allows the reviewing authority the flexibility to use the permitting process that it believes is most appropriate to make a Clean Unit status determination. However, once Clean Unit status has been established through a SIP-approved permitting program, it must be incorporated into the title V permit. *See* section V.C.7 for a discussion of this process.

VI. Pollution Control Projects

A. Description and Purpose of This Action

Our policy is to promote pollution control and prevention projects whenever possible. Today we are finalizing a rule provision that would exclude from major NSR permitting requirements certain work practices and the installation of qualifying pollution control and pollution prevention projects. With these provisions, we are removing a regulatory disincentive that might otherwise prevent industry from undertaking pollution control and prevention measures that result in a net environmental benefit. The ''Pollution Control Project Exclusion'' (or ''PCP Exclusion'') will allow the installation of certain projects that result in net overall environmental benefits to avoid the permitting requirements of major NSR for their collateral emissions increases that exceed the significant level. This action was proposed on July 23, 1996, and closely paralleled our existing policy memorandum [35] which, in effect, enabled a control project exclusion for EUSGUs which was implemented under the electric utility-specific NSR rule (*see* 57 FR 32314, hereinafter ''WEPCO PCP Exclusion'') to apply to all types of sources, and enabled qualifying pollution prevention projects to apply for an exclusion as well. This action will replace both the WEPCO PCP Exclusion and the July 1, 1994 policy guidance with a single, comprehensive NSR exclusion for all types of qualifying PCPs—including add-on controls, switches to less polluting fuels, work practices, and pollution prevention projects. Morever, this final rule will minimize procedural delays in getting a PCP approved, while ensuring appropriate environmental protection.

We define a PCP as an activity, set of work practices, or project at an existing emissions unit that reduces emissions of air pollution from the unit. The PCP Exclusion may be sought when a project is installed at an existing source where it reduces the emissions rate of one air pollutant while causing an increase in emissions of a different, ''collateral'' pollutant. A common example of such a project is installation of a thermal incinerator, which forms NO_X as a collateral pollutant while reducing VOC emissions. For evaluating the environmental impact of a collateral emissions increase, the source and reviewing authority will assess the difference between the emissions unit's post-change actual emissions and its pre-change baseline actual emissions. This test is discussed in section II of today's preamble. That increase is then weighed against the emissions decrease of the primary pollutant to determine whether the PCP, as a whole, provides an environmental benefit. The source and reviewing authority also must ensure that the change does not cause or contribute to an air quality violation, that no ERCs are generated (through initial application of the PCP), and that any significant emissions increase of a nonattainment pollutant is accounted for with acceptable offsets or SIP measures. In performing the air quality analysis under this provision, the procedures established for conducting air quality analysis in conjunction with NSR permitting will be used.

This rule excludes the installation of qualifying PCPs—including add-on control devices, raw material substitutions, work practices, process changes and other pollution prevention strategies—from the definition of ''physical or operational change'' within the definition of major modification in our Federal regulations (*e.g.*, § 52.21). We are also requiring that States adopt the same exclusion in their NSR programs.

The decision to make codifying changes to the existing WEPCO PCP Exclusion and the July 1, 1994 policy guidance draws largely from recommendations of the CAAAC Subcommittee on NSR Reform. The members of the Subcommittee included representatives of State and Federal regulatory agencies, Federal natural resource managers, industry, and environmental and public health interest groups. The Subcommittee's recommendations reflected the consensus of this balanced group of stakeholders.

B. What We Proposed and How Today's Action Compares To It

Our proposed PCP Exclusion provisions essentially restated the July 1, 1994 policy guidance, and incorporated a ''primary purpose'' test as an initial hurdle for candidate PCPs. The ''primary purpose'' test would have limited the exclusion to those projects whose primary function is to reduce air pollution. The proposal, like the previous PCP Exclusion rule and policy guidance, maintained that the exclusion was not applicable to air pollution controls and emissions associated with the construction of a new emissions unit, nor to the replacement or reconstruction of an entire existing emissions unit with a newer or different one. In addition, the fabrication, manufacture, or production of pollution control/prevention equipment and inherently less polluting fuels or raw materials would not, in and of themselves, qualify as a PCP. We also incorporated two safeguards that were taken directly from the WEPCO PCP Exclusion and the July 1, 1994 policy

[35] July 1, 1994 memorandum from John S. Seitz, Director, OAQPS, ''Pollution Control Projects and New Source Review (NSR) Applicability'' and hereinafter referred to as the ''July 1, 1994 policy guidance.''

guidance. First, the reviewing authority would be required to determine that the PCP is ''environmentally beneficial.'' A second safeguard from our proposal would direct reviewing authorities to evaluate the air quality impacts of a proposed PCP and ensure that it does not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We proposed specific add-on control technologies that would be considered presumptively ''environmentally beneficial'' based on their proven history of positive environmental impact. The proposal also allowed for fuel switches to less polluting fuels and substitutions to less potent ozone depleting substances (ODS) to be presumptively environmentally beneficial projects. For other pollution prevention projects and new add-on control technologies to qualify as a PCP, the proposal required the reviewing authority to determine that the project was environmentally beneficial and, additionally for new add-on control devices, that they be ''demonstrated in practice.''

We received comments on every key aspect of the proposed PCP Exclusion. Although most parties support the PCP Exclusion, their suggestions regarding implementation of the exclusion vary considerably. Industry commenters generally desire maximum flexibility, and suggest extending the exclusion to cross-media control projects, limiting the ''environmentally beneficial'' and ''primary purpose'' requirements, allowing for the generation of ERCs from PCPs, and broadening which pollution prevention projects qualified. Other commenters, including State agencies and environmental organizations, generally favor a more restrictive approach that involves more agency oversight and creates more enforceable mechanisms to ensure that the exclusion would not be abused. All comments are specifically addressed in the Technical Support Document.

Today's rule revises the proposed PCP Exclusion in several ways, including the following.

- Eliminating the ''primary purpose'' requirement.
- Expanding the list of presumptively environmentally beneficial projects to include additional control technologies and strategies.
- Enabling projects that otherwise are PCPs and result in utilization increases to qualify for the exclusion.
- Using an actual-to-projected-actual format for determining emissions changes for all source categories to demonstrate net environmental benefit supplemented by air quality analysis under certain circumstances, regardless of their projected emissions increases resulting from utilization.
- Clarifying that the replacement, reconstruction, or modification of an existing emissions control technology could qualify for the exclusion.
- Detailing the calculations for determining whether a switch to a different ODS is environmentally beneficial.
- Changing the visibility component of the air quality analysis to ''an air quality related value (such as visibility) that has been identified for a Federal Class I area by a FLM, and for which information is available to the general public''.
- Identifying which fuel switches are presumed ''inherently less polluting''.
- Enabling work practice standards to qualify for the exclusion.
- Clarifying that modeling for air quality impacts analyses may use projected actual emissions.
- Detailing proper noticing requirements for listed projects to use this exclusion.
- Describing in detail the process for granting the PCP Exclusion for non-listed control technologies and pollution prevention strategies.
- Disqualifying projects that cannot secure acceptable offsetting emissions reductions or SIP measures for PCPs resulting in a significant net increase of a nonattainment pollutant.
- Disallowing generation of netting and offset credits from the initial application of PCPs that qualify for this exclusion.
- Clarifying that non-air pollution impacts will not be considered in the ''environmentally beneficial'' determination.

By today's action we are superseding the PCP regulatory exclusion that applied only to EUSGUs. Today's action covers all types of sources, including EUSGUs. The new, broader PCP Exclusion will ensure equitable treatment of all source categories and remove any disincentive for companies that wish to install pollution control and pollution prevention projects, to the extent allowed by the CAA. Thus, owners or operators of EUSGUs who want a PCP Exclusion may, like any other source category, use the expanded definition of ''pollution control project,'' which includes the lengthened list of environmentally acceptable control devices. Despite today's rule revisions addressing a broader array of pollution control and pollution prevention projects at a larger variety of sources, we feel that the rule's procedures are less complex than and are clearer than the WEPCO PCP Exclusion and the July 1, 1994 policy guidance. We are satisfied that the final PCP Exclusion best achieves the goals of minimizing regulatory burden and reducing procedural delays for projects that ensure net overall environmental protection.

1. Applicability

a. *What types of projects may qualify for the PCP Exclusion?*

In the WEPCO PCP Exclusion, we found that installation of add-on emissions control projects, switches to less polluting fuels, and certain clean coal demonstration projects could be PCPs, ''unless the project renders the unit less environmentally beneficial.'' 57 FR 32319. Today's rule affirms that these types of projects are appropriate candidates for the exclusion, and it expands the types of projects that can qualify to include installation of other control devices that were not previously listed in the regulations, as well as work practice standards and switches to less potent quantities of ODS. Some of the control technologies (for example, oxidation/absorption catalyst and biofiltration) listed in today's revisions were either not well known or not demonstrated in practice as of the release of the WEPCO PCP Exclusion and the July 1, 1994 policy guidance exclusion; consequently, today's rule brings the list of approved PCPs up to date.

We believe that the overall net impact of installing and operating the listed add-on control systems is environmentally beneficial and that such projects are desirable from an environmental perspective. The add-on controls in the approved list historically have been applied to many different kinds of sources to reduce emissions. They have been consistently used because it is generally understood that, from an overall environmental perspective, these controls are effective in reducing emissions when they are applied to existing plants in a manner consistent with standard and reasonable practices. Certain pollution prevention projects—for example, fuel switches and low-NO_X burners—are also presumed to be environmentally beneficial when properly applied. Consequently, as part of the exclusion for PCPs, we do not require a case-by-case ''environmentally beneficial'' demonstration for the ''listed'' PCPs, as long as they are properly applied and site-specific factors do not indicate that their application would be environmentally harmful. Thus, the ''environmentally beneficial'' presumption created by the list may be rebutted. For companies wishing to install and operate non-listed PCPs, however, the process is more rigorous. In these cases, the reviewing authority first must consider case-specific factors to determine whether the non-listed project results in a net environmental benefit and then must provide an opportunity for, and respond to, public notice and comment before approving the project as a PCP.

b. Why does the PCP Exclusion not apply to greenfield sources?

Today's rule restricts applicability of the PCP Exclusion to physical changes being made at existing sources. Installing or implementing a project on an existing source is more likely to improve the environment than is the construction of a new source, since one can reasonably expect a PCP to reduce overall emissions, barring a considerable utilization increase. New sources, however, introduce new emissions to the air without reducing existing emissions, and consequently should be as clean as possible. Furthermore, new emissions units are among the major capital investments in industrial equipment, which are the very types of projects that Congress intended to address in the NSR provisions when such projects result in an overall emissions increase from the major stationary source. Thus, when emissions from a new source exceed the significant level, they are subject to NSR, and all emissions that are generated from the new project should be addressed in the major NSR permit evaluation for the major stationary source.

c. Does the PCP Exclusion apply to rebuilt or upgraded control devices?

We are clarifying in today's rule that upgrading or replacing existing emissions control equipment with a more effective emissions control project can qualify for the PCP Exclusion. However, the new PCP would have to result in a level of control more stringent than the original control equipment, in terms of emissions rate or output-based emissions rate, such as upgrading a scrubber to increase removal efficiency. Another example that would qualify is a control device that achieves an emissions reduction equivalent to that of the original device, but is more energy efficient. An example of this is the conversion of a thermal oxidizer to a catalytic oxidizer. As long as the catalytic oxidizer achieved emissions control equivalent to that of the thermal oxidizer, it would qualify for a PCP Exclusion since it reduces energy use.

2. Environmental Benefits

a. *What projects do we presume to be environmentally beneficial?*

Commenters recommend that we expand the list of presumptively environmentally beneficial projects to include other add-on control technologies that are commonly used to reduce emissions at major stationary sources. We agree with this recommendation and have expanded the list of presumptively environmentally beneficial PCPs accordingly in today's rule.

We presume the projects listed in Table 2 are environmentally beneficial. We based our decision to add certain projects to the list on two criteria: (1) The PCP is ''demonstrated in practice''; and (2) its overall effectiveness in reducing emissions of the primary pollutant(s) when balanced against its potential for emissions increases of collateral pollutant(s).

TABLE 2—ENVIRONMENTALLY BENEFICIAL POLLUTION CONTROL PROJECTS

Control device/PCP	Pollutant controlled
Conventional & advanced flue gas desulfurization.	SO_2
Sorbent injection	
Electrostatic precipitators	Particulates and other pollutants.
Baghouses	
High efficiency multiclones	
Scrubbers	
Flue gas recirculation	NO_X
Low-NO_X burners or combustors	
Selective non-catalytic reduction	
Selective catalytic reduction	
Low emission combustion (for internal combustion engines)	
oxidation/absorption catalyst (e.g., $SCONO_X$ ™)	
Regenerative thermal oxidizers	VOC and HAP.
Catalytic oxidizers	
Thermal incinerators	
Hydrocarbon combustion flares [36]	
Condensers	
Absorbers & adsorbers	
Biofiltration	
Floating roofs (for storage vessels)	

[36] For the purposes of these rules, ''Hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including use of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions from waste streams comprised predominantly of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

Other presumed environmentally beneficial PCPs include activities or projects undertaken to accommodate: (1) switching to different ODS with a less damaging ozone-depleting effect (factoring in its ozone depletion potential and projected usage); and (2) switching to an inherently less polluting fuel, to be limited to the following.

- Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel. (that is, from a higher sulfur content #2 fuel, or from #6 fuel, to CA 0.05 percent sulfur #2 diesel)
- Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal.
- Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood
- Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content)
- Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content)

We are presuming that the application of a PCP listed above is environmentally beneficial and would be eligible for a PCP Exclusion. This presumption is premised on an understanding that you will design and operate the controls in a manner that is consistent with proper industry, engineering, and reasonable practices, and that you minimize increases in collateral pollutants within the physical configuration and operational standards usually associated with the emissions control device or strategy. You will be required to certify that this is true in the notification you send your reviewing authority.

As stated before, the ''environmentally beneficial'' determination is a presumption, so it can be rebutted in cases in which a reviewing authority determines that a particular proposed PCP project would not be environmentally beneficial. Also, this presumption does not apply when: (1) The PCP is not designed, operated, or maintained in a manner consistent with standard and reasonable practices; (2) the collateral pollutant emissions increases are not minimized within the physical configuration and operational standards usually associated with the emissions control device or strategy; or (3) the unit will be less environmentally beneficial. Also, when a reviewing authority determines that an otherwise listed project would not be constructed and operated consistent with standard practices, it may rebut the ''environmentally beneficial'' presumption for that application of the technology.

Finally, it should be noted that commenters on the proposed rule list several examples of specific projects they believe we should add to the list of presumptively environmentally beneficial projects. However, some of these suggested PCP scenarios would never trigger NSR because there would not be a significant increase in emissions, from either the collateral or primary pollutant. For example, one commenter says we should consider the termination or decommissioning of an emissions unit an environmentally beneficial technology. We have never required a unit to undergo NSR before terminating operation; consequently, there is no need for a PCP Exclusion. Commenters raised other scenarios but provided few examples and insufficient detail from which we could draw any conclusions. We believe that the PCP Exclusion will benefit only a subset of all PCPs undertaken at existing sources, in part because most control projects will not cause an emissions increase of any criteria pollutant and, thus, will not trigger NSR. As always, major NSR only applies to your physical or operational changes that result in a significant net emissions increase at your source.

b. What is Meant by ''Environmentally Beneficial''?

The WEPCO PCP Exclusion defines a PCP as ''any activity or project undertaken . . . for purposes of reducing emissions.'' § 52.21(b)(32). We have explained that ''EPA expects that most, if not all, pollution control projects will reduce net actual emissions.'' 57 FR 32319 (1992). The WEPCO PCP Exclusion therefore ''avoids the need to undertake a quantitative emissions increase calculation in every case'' that a facility prepares to undertake a PCP. Rather, in recognition that while a PCP ''could theoretically cause a small collateral increase in some emissions, it will substantially reduce emissions of other pollutants,'' the rule contemplates that sources proposing PCPs that are not listed will determine in the first instance whether they are entitled to the PCP Exclusion based on the ''project's net emissions and overall impact on the environment.'' *Id.* at 32321. Nevertheless, ''the reviewing authority can require additional modeling under certain circumstances to evaluate the air quality impact of a [PCP].'' *Id.*

As for the WEPCO PCP Exclusion, ''reducing emissions'' is the bedrock of the PCP Exclusion. For the list of PCPs in today's regulation, we are satisfied that the net impact on the environment from these projects is beneficial because of our broad experience with these technologies. Consequently, such projects are desirable from an environmental protection perspective, and we have no reason to doubt the validity of the ''environmentally beneficial'' presumption when such controls are applied to existing sources consistent with standard and reasonable practices.

For those projects not listed in Table 2, there is no presumption as to whether or not the projects are environmentally beneficial, and therefore the PCP Exclusion is not self-executing. On a case-by-case basis, your reviewing authority must consider the net environmental benefit of a non-listed project and approve requests for the PCP Exclusion for a specific application of the project upon a showing that it is environmentally beneficial. You must receive this approval from your reviewing authority before beginning actual construction of the PCP. This approval must be conducted through a SIP-approved permitting process that conforms to the requirements of §§ 51.160 and 51.161, including a requirement for a public hearing and 30-day public comment period on all aspects of the project. This includes an opportunity for the public and EPA to review and comment on the environmental benefits analysis and the air quality impacts assessment. The reviewing authority's evaluation of the project's net environmental benefits is limited to air quality considerations; specifically, the air quality benefits of emissions reductions of the primary pollutant must outweigh any detrimental effects from emissions increases in the collateral pollutant, when comparing the unit's post-change emissions to its pre-change baseline actual emissions. Also, the reviewing authority's decision on a case-specific approval of a PCP Exclusion does not serve to proclaim that a given technology is environmentally beneficial for purposes of subsequent PCP Exclusion applications for the same technology.

We may add non-listed control devices, work practices, and pollution prevention projects to the approved list, such that a previously non-listed project can be considered for a self-executing PCP Exclusion. The technology must be reviewed by us to ensure that the project's overall net impact on the environment is indeed beneficial. Our evaluation would hinge on the same factors mentioned above for the reviewing authority's case-by-case reviews. Once ''listed,'' a subsequent project could be presumed environmentally beneficial unless case-specific factors or impacts would indicate otherwise.

Today's rule also provides more guidance in this rule on what constitutes an environmentally beneficial fuel switch. In general, we lack sufficient information from which to categorically determine that a switch to solid fuel will be ''inherently less polluting.'' For instance, switching from oil to woodwaste may decrease sulfur emissions while increasing particulate emissions. Switching between solid fuels, such as coal, woodwaste, or tire-derived fuels, must therefore be evaluated more closely before we can determine whether such a switch could qualify as an environmentally beneficial PCP. Accordingly, we specify which fuel switches are presumptively available for the PCP Exclusion.

c. Why are not More Pollution Prevention Projects Presumed Environmentally Beneficial?

Switching to a less polluting fuel or to a less potent quantity of ODS are prime examples of pollution prevention projects, and both are already listed as presumptively environmentally beneficial. However, some commenters point out that there are far more end-of-pipe, add-on technologies that are listed as environmentally beneficial and recommend that we include more pollution prevention technologies. Although we fully support and encourage pollution prevention projects and strategies, special care must be taken in evaluating a pollution prevention project for the PCP Exclusion. Pollution prevention projects tend to be dependent on site-specific factors and lack an historical record of performance, which proves problematic in deciding whether they are environmentally beneficial when applied universally. We believe that both add-on control devices and pollution prevention projects have equal chances of being presumed environmentally beneficial, but we have more data and history with the add-on control equipment, and this is why the list includes more of those types of pollution strategies. Pollution prevention projects can still qualify as environmentally beneficial PCPs, but they must be evaluated by the reviewing authority to confirm their environmental benefits.

d. How are Control Technologies and Pollution Prevention Strategies Added to the Presumptively "Environmentally Beneficial" List?

The proposal would have allowed the reviewing authority to add to the list of presumptively environmentally beneficial technologies, as long as it determined that a project had been "demonstrated in practice" and was comparable in effectiveness to the listed technologies on a pollutant-specific basis. We will continue to allow new control technologies that are demonstrated in practice to be added to the list of presumed environmentally beneficial technologies. However, unlike the proposed PCP Exclusion, we will not require that non-listed technologies be comparable in effectiveness on a pollutant-specific basis with the emissions reduction efficiency of currently listed technologies in order to qualify as environmentally beneficial, since this is difficult to compare when different pollutants must be considered. Also, today's rule vests the EPA Administrator with the sole authority to approve non-listed pollution strategies as presumptively environmentally beneficial. The reviewing authority may perform a case-specific approval of a PCP Exclusion in which it would determine that a non-listed technology is environmentally beneficial, but that determination only pertains to the particular case under evaluation and would not serve to presume that the technology is environmentally beneficial for subsequent applications.

Through notice and comment rulemaking, we will maintain and update the list as we deem additional technologies to be environmentally beneficial or to remove from the list any PCP that we erroneously listed.

Several commenters on the proposal suggest that we create a clearinghouse for newly added environmentally beneficial PCPs. We agree that additions to the approved PCP list need to be readily available to the public; however, since rulemaking will be used to add new PCPs to the approved list, no additional public notice will be necessary.

e. How do I Calculate Emissions Increases?

In order to calculate emissions increases for primary and collateral pollutants for the purpose of determining the environmental impact of the PCP, you must use the actual-to-projected-actual applicability test method for calculating the emissions increase. This test is discussed in section II of today's preamble, and is consistent with the remainder of today's rule revisions.

f. How do you Perform the Emissions Calculation for Switches to a Less Potent Amount of ODS?

We have determined that activities or projects undertaken to accommodate switching to an ODS with less potential for stratospheric ozone damage are presumptively environmentally beneficial, as long as the productive capacity of the equipment does not increase as a result of the activity or project.

For determining your emissions before and after the change, you must perform a weighted comparison of the switch based on ozone depleting potential (ODP), taken from 40 CFR part 82, and the past and projected future usage of each ODS. In cases where we have expressed a chemical's ODP in 40 CFR part 82 as a range, the most conservative value (that is, the upper bound value) should be used. The replaced ODP-weighted amount is then calculated by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS. The projected ODP-weighted amount is computed by multiplying the projected future annual usage of the new substance by its ODP. The following example illustrates how to make these calculations in determining whether a switch to a different ODS is environmentally beneficial.

Example: Source plans to replace solvents in its batch process line. Its current solvent, CFC–12, a chlorofluorocarbon (CFC) with an ODP of 1.0, is emitted at 200 tpy. It will be substituted with a less potent solvent, a hydrochlorofluorocarbon (HCFC) with an ODP of 0.02. As a result of this change, the straight mass emissions coming from the solvent will increase twofold due to the new process solvent having a higher vapor pressure than the old solvent. However, this substitution most likely would be viewed as environmentally beneficial, since the ODP-weighted emissions would reveal a decreased risk in environmental harm. Specifically, the CFC–12 would be multiplied by its ODP of 1.0, resulting in 200 tpy for pre-change ODP-weighted emissions. In contrast, the 400 tpy of HCFC emissions would be multiplied by 0.02, giving it a post-change, ODP-weighted emission level of 8 tpy. The net effect is an emissions decrease of 192 tpy on an ODP-weighted basis.

g. Should Cross-Media Impacts be Considered in the "Environmentally Beneficial" Demonstration?

By definition, a PCP reduces emissions of air pollutants subject to regulation under the Act. Therefore, while the primary environmental benefit of the PCP would be to reduce air emissions, a secondary benefit could be reducing pollution in other media. However, these cross-media tradeoffs are difficult to compare, so it is difficult to weigh their importance in appraising the overall environmental benefit of a PCP. We solicited comments in the proposal on how to compare cross-media pollution, but we received no suggestions on how to design such a system. As a result, we have determined that it is inappropriate to consider non-air impacts when considering whether projects, activities, or work practices qualify for the PCP Exclusion.

3. Air Quality Impacts

a. What is the "Cause-or-Contribute Test"?

Another criterion for qualification for all PCPs is that the emissions from the PCP cannot cause or contribute to a violation of any NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM, and for which information is available to the general public. This has been called the "cause-or-contribute test." We continue to believe that the PCP Exclusion must include such safeguards to ensure protection of the environment and public health. In the WEPCO PCP Exclusion, we said that the reviewing authority "under certain circumstances" may evaluate the air quality impact of a PCP. 57 FR 32321. Generally, these circumstances would include large secondary emissions increases in areas that are nonattainment, or marginally in attainment, for the pollutant in question. We anticipate, however, that such analyses would not normally be required, since collateral emissions increases from most relevant projects will be so small that additional modeling should not be required.

Commenters from industry complain that determining whether there would be an adverse impact on an AQRV is too difficult and believe that the proposal is ambiguous in defining roles of FLMs and reviewing authorities. The intention of the statutory structure for preconstruction permit review in section 165(d) of the Act unambiguously is to protect against any adverse impact on AQRVs in Class I lands. Therefore, we continue to believe that any air quality assessment for a PCP should consider all relevant AQRVs in any Class I area that are identified by the FLM at the time you submit your notice or permit application for the project. For purposes of those projects on the list of projects presumptively qualifying for the PCP Exclusion, we are limiting the consideration of AQRVs to those that have already been identified by an FLM for the Federal Class I area. You should check with the National Park Service website and other public information to determine if the FLM has already identified an AQRV for a nearby Class I area. If you are required to obtain both approval from your reviewing authority and a permit before beginning actual construction of your project, then additional AQRVs may be identified by an FLM consistent with the procedures provided for in that permitting process.

b. What is Necessary for the Air Quality Impacts Analysis?

Reviewing authorities can require you to analyze your air quality impacts whenever they have reason to believe that: (1) the project will result in a significant emissions increase of any criteria pollutant over levels in the most recent analysis; and (2) such an increase would cause or contribute to a violation of any NAAQS or PSD increment or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. The analysis must contain sufficient data to satisfy the reviewing authority that the new levels of emissions will not cause or contribute to a violation of the NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. If the air quality analysis shows that a resulting violation is foreseeable, your project cannot receive the PCP Exclusion.

Many industry commenters complain that the proposed air quality analysis and Class I provisions for the exclusion were overly burdensome and needed to be either eliminated or streamlined. We agree in part with this point, even though we strongly contend that there need to be safeguards to protect against misuse of the exclusion with projects that will not provide positive environmental results. Although today's final rule contains the core safeguard to prevent an adverse air quality impact, a modeling exercise is not necessarily warranted in all cases.

While you are not required to notify the FLM of any Federal Class I area located near your facility as a prerequisite for proceeding with a PCP, you must determine whether any AQRVs have been identified in these areas. FLMs have identified AQRVs for many of the Federal Class I areas and made this information available on a dedicated web site (*http://www2.nature.nps.gov*). If no AQRVs have been identified for a particular Class I area, your demonstration is simply a statement that no AQRVs exist in Class I areas that your source has the potential to affect. Similarly, if there are AQRVs in nearby Federal Class I areas, but the pollutants associated with these AQRVS either will not be emitted by your facility or will not increase by a significant amount as a result of the PCP, then your demonstration should simply indicate the lack of any association between your PCP project and the known AQRVs.

On the other hand, you should be prepared to conduct modeling with respect to any regulated NSR pollutant that your PCP will cause to increase by a significant amount when that pollutant is associated with a known AQRV in a nearby Federal Class I area. Oftentimes, a screening model may be used to estimate the ambient impacts of the increase from your facility. Special concern should be given in cases where an FLM has already identified adverse impacts for such AQRV. In such cases, you are expected to record and consider any information that the FLM has made available concerning the adverse effects, to help determine whether the pollutant impacts from your facility have the potential to cause further adverse impacts.

If a reviewing authority, upon receiving your notification of using the PCP Exclusion, believes that an air quality impacts analysis is reasonably necessary, it is entitled to request more information from you, including additional local or regional modeling.

c. How does the PCP Exclusion Apply to Projects With Collateral Pollutant Increases of Nonattainment Pollutants?

The PCP Exclusion is available, regardless of an area's attainment status or its severity of nonattainment. Nonetheless, because increases in a nonattainment pollutant contribute to the existing nonattainment problem, you or the reviewing authority must offset with acceptable emissions reductions any significant emissions increase in a nonattainment pollutant resulting from a PCP. We are promulgating the PCP Exclusion consistent with our proposal's approach of requiring mitigation of any significant emissions increase of a nonattainment pollutant resulting from a PCP.

Since less than significant collateral emissions increases (for example, less than 40 tpy of VOC in a moderate ozone nonattainment area) do not trigger major NSR, such mitigation requirements are not necessary for the PCP Exclusion when the increase of the nonattainment pollutant will be below the applicable significant level. Be aware, however, that a less than significant emissions increase may be subject to a State's minor NSR requirements.

4. Miscellaneous

a. Can you Generate ERCs From Your PCP-Excluded Project?

The proposal would have allowed certain projects approved for the PCP Exclusion to use their primary pollutant(s) emissions reductions as NSR offsets or netting credits. We included in the proposed rule a specialized ''environmentally beneficial'' test that would apply to PCPs that generate ERCs. Some commenters support allowing ERCs and creating more flexibility to use them. However, other commenters recommend that EPA avoid complicating the PCP Exclusion by factoring emissions trading credits with the exclusion. These commenters claim that the parceling out of the appropriate reductions for emissions credits and for the newly installed PCP would take an enormous amount of time, and cause problems with tracking emissions reductions and using the credits.

We no longer believe it would be prudent to allow PCPs to generate netting credits or offsets for the emissions reductions used to initially qualify the project for the PCP Exclusion, in light of the issues of increased complexity that the commenters raise. But perhaps more importantly, we feel that the emissions reductions initially achieved by the PCP are integral to the ''environmentally beneficial'' demonstration required in order for the PCP to qualify for the exclusion. The emissions reductions are traded, in effect, for the significant emissions increase of the collateral pollutants and for the benefits of being excluded from the major NSR permitting requirements. To then re-use the reductions would weaken the PCP Exclusion and would not ensure appropriate environmental protection. Consequently, you cannot use emissions reductions that initially qualified a project for the PCP Exclusion as netting credits or offsets.

However, you are allowed to continue to use these reductions to generate allowances for purposes of complying with the title IV Acid Rain program. In

1992, the PCP Exclusion was originally designed for use by EUSGUs because we did not envision that Congress intended for the NSR program to apply to projects undertaken to comply with title IV. Nothing in today's proposal is intended to change that design.

Moreover, once you qualify for the PCP Exclusion, you can apply for ERCs if you change your process conditions in such a way that further reduces emissions. For example, consider that you have an add-on control technology which receives a PCP Exclusion that, at full operation, allows the source to increase its emissions of a specific collateral pollutant and emit 100 tpy of a pollutant (either a targeted pollutant or a collateral pollutant). If you later decide to take an hours-of-operation limit for your process line and/or control technology that reduces your emissions of that pollutant to 75 tpy, then this 25 tpy reduction in emissions can be used as ERCs if deemed acceptable in all other respects by your reviewing authority.

b. Why Are We Deleting the ''Primary Purpose'' test?

The ''primary purpose'' test was proposed as an initial screening mechanism for reviewing authorities to screen out inappropriate projects and to streamline the approval process. This was designed to help reviewing authorities avoid dedicating unnecessary resources to non-qualifying projects. Furthermore, we recognized that all of the listed PCPs have a primary purpose of reducing air pollution, so it followed logically that any other PCP should have the same primary purpose.

However, we received comments from both industry and a State trade association stating that many activities and projects have multiple purposes in addition to reducing emissions, and they encourage EPA not to focus on the primary purpose of a project, but rather on the project's net environmental benefit, in considering it for a PCP Exclusion. A ''primary purpose'' requirement would disqualify projects that may be environmentally beneficial but happen to not have pollution control as their primary purpose. Further, one commenter stated that by focusing on the intent of the project rather than its end result, administrative agencies will unnecessarily be forced to devote scarce resources to making these determinations.

We concur with these comments and have determined that this test is potentially unnecessarily restrictive. Our primary objective in allowing for a PCP Exclusion is to offer NSR relief for those projects that create a net environmental benefit, and thus we should not concern ourselves with a source's motivation for undertaking its project. Therefore, by today's rule revisions, even if a project's primary purpose is not to reduce emissions, it can still qualify for the PCP Exclusion if it meets the ''environmentally beneficial'' and air quality tests set forth in today's regulations.

c. How Do the Listed PCP Technologies Compare to BACT or LAER Determinations?

The list of presumed environmentally beneficial technologies contains several control strategies that do not qualify as BACT or LAER. For example, installing low-NO_X burners on large-sized turbines would rarely constitute an acceptable BACT level. However, these projects are presumed environmentally beneficial and are eligible for the PCP Exclusion from major NSR because these controls are cleaner than the existing equipment is without the controls. In addition, the PCP Exclusion only applies to sources that are installing PCPs, and not to the installation of new emissions units or changes that increase the capacity of the unit, both of which would be potentially subject to BACT or LAER. We reiterate, however, that merely because a control technology is listed as environmentally beneficial does not also imply that the technology is equivalent to BACT or LAER, and you should not rely on any such implication as a presumptive BACT or LAER determination.

d. Is the Intent of the PCP Exclusion to Allow Collateral Pollutant Emissions to go Uncontrolled?

To qualify for the PCP Exclusion, you must minimize emissions of collateral pollutants within the physical configuration and operational standards usually associated with the emissions control device or strategy. This typically occurs by inherent design of the control device that causes them. In most cases, no additional control requirements will be necessary.

e. What Does ''Demonstrated in Practice'' Mean?

Representatives from industry comment that we should ease restrictions that require new add-on technologies to be demonstrated in practice. We are continuing to require that new technologies be demonstrated in practice before being added to the list, in part because this is an important element in a showing that the candidate technology is environmentally sound. However, we have expanded the meaning of ''demonstrated in practice'' to include technologies demonstrated outside of the United States.

f. How Can the Public Participate in the PCP Exclusion Decision for Your Project?

By these rule revisions, we are not requiring any review of your PCP by the public or your reviewing authority prior to enabling the use of the exclusion. Nonetheless, existing State regulations for minor NSR will continue to apply to projects that qualify for the PCP Exclusion and are not otherwise excluded under the State program. Minor NSR programs are designed to consider the impact these increases could have on air quality, including whether local conditions justify rebutting the presumption that a listed project is environmentally beneficial. Nothing in this rule voids or otherwise creates an exclusion from any otherwise applicable minor NSR preconstruction review requirement in any SIP that has been approved pursuant to section 110(a)(2)(C) of the Act and 40 CFR 51.160 through 51.164. The minor NSR permits may afford the public an opportunity to review and comment on the use of the PCP Exclusion for a specific project. *See* §§ 51.160 and 51.161. Furthermore, to undertake a PCP Exclusion, you could use the title V permit revision process to officially effect the PCP Exclusion. This would enable the public to review the PCP determination at that time.

Thus, the process for implementing a PCP Exclusion would be similar to the other exemptions within NSR (routine maintenance, change in ownership, etc.) whereby you are empowered to make the proper decision based on the facts of the case and the rule requirements.

C. Legal Basis for PCP

In 1992, we revised the NSR regulations to exclude PCPs at existing EUSGUs. *See* 57 FR 32314 (July 21, 1992), amending §§ 51.165(a)(1)(v)(C)(8), 51.166(b)(2)(iii)(h), and 52.21(b)(2)(iii)(h). There, we stated that we believed ''that Congress did not intend that PCPs be considered the type of activity that should trigger NSR.'' 57 FR 32319. Although the 1992 rulemaking applied only to EUSGUs, we believe that Congress's intention holds true for other industry sectors as well. Congress could not have intended to require that, and the Act should not be construed such that, physical or operational changes undertaken to reduce emissions undergo NSR. Therefore, in today's action, we are revising the PCP Exclusion and removing the conditions limiting it to EUSGUs.

In the event that a PCP results in a significant emissions increase of a different pollutant, the reviewing authority may require an analysis of air quality impacts which would serve the same function as an air quality impacts analysis conducted as part of NSR permitting. Providing an exclusion for PCPs enables facilities to reduce emissions without having to wait for a major NSR permit to be issued. We believe that this result is consistent with the objectives of the NSR provisions in the CAA. Thus, we are revising our rules to remove disincentives to pollution control and pollution prevention projects to the extent allowed under the CAA.

D. Implementation

1. How Do You Apply For and Receive a PCP Exclusion?

The process for obtaining a PCP Exclusion basically breaks down into two separate scenarios, depending on whether your proposed project is ''listed'' or ''non-listed'' as environmentally beneficial. Both processes are presented below.

a. What Is the Process You Must Follow for Projects Involving Listed PCPs?

Before you begin actual construction on your PCP, you must submit a notice to your reviewing authority that includes the following information (and depending on your reviewing authority's requirements, this information may be submitted with a part 70, part 71 or other SIP-approved permit application such as a minor NSR permit application): (1) A description of project; (2) an analysis of the environmentally beneficial nature of the PCP, including a projection of emissions increases and decreases (speciated, using an appropriate emissions test for the emissions unit); and (3) a demonstration that the project will not have an adverse air quality impact.

You may begin construction on the PCP immediately upon submitting your notice to the reviewing authority. However, if your reviewing authority determines that the source does not qualify for a PCP Exclusion, you may be subject to a delay in the project or an order to not undertake the project.

b. What Is the Process You Must Follow for Projects Involving Non-Listed PCPs?

For projects not listed in Table 2, on a case-by-case basis your reviewing authority must consider the net environmental benefit of a non-listed project and, within a reasonable amount of time, act upon your request for the exclusion for a specific application. You must receive this approval from your reviewing authority before beginning actual construction of the PCP. Your reviewing authority will provide an opportunity for public review and comment prior to granting its approval for the PCP.

Your application for case-specific approval of a PCP Exclusion should have the same information as required above for a notice to use a listed technology. The only difference between the two processes is that the use of a listed technology allows you to commence construction on your PCP immediately after submitting your notice to the reviewing authority, whereas the use of a non-listed technology requires you to first submit an application to your reviewing authority and obtain its approval prior to construction of your PCP.

2. What Process Will We Follow To Add New Projects to the List of Environmentally Beneficial PCPs?

We will use notice and comment rulemaking procedures to add new projects to the list of PCPs that are presumed to be environmentally beneficial. We may take this action on our own initiative or you may petition us, if you believe there is a project that should be added to the list.

If you submit a petition to us requesting that a non-listed air pollution control technology (which includes pollution prevention or work practices) be determined environmentally beneficial and presumptively qualified for the PCP Exclusion, you should describe the anticipated emissions consequence of installing the PCP, both for primary and collateral pollutants. We will review your submittal within a reasonable amount of time. If we believe that the project should be added to the list, we will amend the list of approved PCPs through rulemaking. Once the rule has been amended, you may use a newly listed PCP if you proceed in accordance with the process for implementing the PCP Exclusion for listed PCPs. (*See* section VI.D.1.a.)

3. What Are Our Operational Expectations for an Excluded PCP?

By this rule, we are creating a general duty for all sources approved to use a PCP Exclusion. This general duty clause requires you to operate the PCP in a manner consistent with reasonable engineering practices and with the basic applicability requirements for the exclusion (*i.e.*, being environmentally beneficial and having no adverse air quality impacts). This means that you have a legal responsibility to operate in a manner that is consistent with your analysis of the environmental benefits and air quality impacts analysis, and that you will minimize collateral pollutant increases within the physical configuration and operational standards usually associated with the emissions control device or strategy.

4. What Are the Implications of Not Complying With the PCP Exclusion Process?

The PCP Exclusion is a mechanism for bypassing the major NSR permitting requirements. If you do not comply with the steps necessary to qualify for the PCP Exclusion under the terms of the PCP provisions, you can become subject to major NSR.

VII. Listed Hazardous Air Pollutants

The 1990 Amendments to the CAA at section 112(b)(6) exempted HAP listed under section 112(b)(1) from the PSD requirements in part C. In our 1996 **Federal Register** Notice, we proposed changes to the regulations at §§ 51.166 and 52.21 to implement this exemption. Specifically, we proposed the following.

• The HAP listed in section 112(b)(1), as well as any pollutant that may be added to the list, are excluded from the PSD provisions of part C. These HAP include arsenic, asbestos, benzene, beryllium, mercury, radionuclides, and vinyl chloride, all of which were previously regulated under the PSD rules. This exemption applies to the provisions for major stationary sources in §§ 51.166(b)(2) and 52.21(b)(2), the significant levels in §§ 51.166(b)(23)(i) and 52.21(b)(23)(i), and the significant monitoring concentrations in §§ 51.166(i)(8) and 52.21(i)(8).

• Pollutants listed in regulations pursuant to section 112(r)(1), Accidental Release, are not excluded from the PSD provisions of part C.

• Any HAP listed in section 112(b)(1) that are regulated as constituents or precursors of a more general pollutant listed under section 108 are still subject to PSD, despite the exemption in section 112(b)(6).

• If a pollutant is removed from the list under the provisions of section 112(b)(3) of the Act, that pollutant would be subject to the applicable PSD requirements of part C if it is otherwise regulated under the Act.

• Pollutants regulated under the Act and not on the list of HAP, such as fluorides, TRS compounds, and sulfuric acid mist, continue to be regulated under PSD.

Public commenters generally agree that our proposal reflects the statutory requirements. Therefore, today we are taking final action to promulgate these proposed provisions at §§ 51.166(b)(23)(i), 51.166(i)(8), 52.21(b)(23)(i), and 52.21(i)(8).

As today's regulations provide, the following pollutants currently regulated under the Act are subject to Federal PSD review and permitting requirements.

- CO
- NO_X
- SO_2
- PM and particulate matter less than 10 microns in diameter (PM–10)
- Ozone (VOC)
- Lead (Pb) (elemental)
- Fluorides (excluding hydrogen fluoride)
- Sulfuric acid mist
- H_2S
- TRS compounds (including H_2S)
- CFCs 11, 12, 112, 114, 115
- Halons 1211, 1301, 2402
- Municipal Waste Combustor (MWC) acid gases, MWC metals, and MWC organics
- ODS regulated under title VI

The PSD program applies automatically to newly regulated NSR pollutants, which would include final promulgation of an NSPS applicable to a previously unregulated pollutant.

As we indicated in our proposal package, CAA section 112(b)(7) states that elemental Pb (the named chemical) may not be listed by the Administrator as a HAP under section 112(b)(1). Therefore, because section 112(b)(6) exempts only the pollutants listed in section 112, elemental Pb emissions are not exempt from the Federal PSD requirements. Elemental Pb continues to be a criteria pollutant subject to the Pb NAAQS and other requirements of the Act. As proposed, we are also continuing to maintain that the reference to Pb in the regulations regarding the significant levels and significant monitoring concentrations covers the Pb portion of Pb compounds. *See* §§ 51.166(b)(23), 51.166(i)(8), 52.21(b)(23), and 52.21(i)(8). Otherwise, the word elemental might imply that only Pb that is not part of a Pb compound is covered.

One commenter requests that we amend the regulations to include a definition of pollutants regulated under the Act. We agree with the commenter that such a provision would clarify which pollutants are covered under the PSD program. Moreover, the nonattainment NSR rules at § 51.165 would also benefit from this clarity. Therefore, today's final regulations include a definition for regulated NSR pollutant. This new definition replaces the terminology ''pollutants regulated under the Act.''

The term ''Regulated NSR pollutant'' includes the following pollutants.

- NO_X or any VOC
- Any pollutant for which a NAAQS has been promulgated
- Any pollutant that is subject to any standard promulgated under section 111 of the Act
- Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act.

The new definition excludes HAPs listed in section 112 of the Act (including any pollutants that may be added to the list pursuant to section 112(b)(2) of the Act). However, when any pollutant listed under section 112 of the Act is also a constituent or precursor of a more general pollutant that is regulated under section 108 of the Act, that listed pollutant may be regulated under NSR but only as part of regulation of the general pollutant.

As we indicated in our proposal, State and local agencies with an approved PSD program may continue to regulate the HAP now exempted from Federal PSD by section 112(b)(6) if their PSD regulations provide an independent basis to do so. These State and local rules remain in effect unless they are revised to provide similar exemptions. Such provisions that are part of the SIP are federally enforceable.

Section 112(q) retains existing NESHAP regulations by specifying that any standard under section 112 in effect before the enactment of the 1990 Amendments remains in force. Therefore, the requirements of §§ 61.05 to 61.08, including preconstruction permitting requirements for new and modified sources subject to existing NESHAP regulations, are still applicable.

Pollutants listed under section 112(r) are not included in the definition of regulated NSR pollutant. As we proposed, substances regulated under section 112(r) may still be subject to PSD if they are regulated under other provisions of the Act. For example, even though H_2S is listed under section 112(r), it is still regulated under the Federal PSD provisions because it is regulated under the NSPS program in section 111. This means that the listing of a substance under section 112(r) does not exclude the substance from the Federal PSD provisions; the PSD provisions apply if the substance is otherwise regulated under the Act.

We are not taking final action on ambient impact concentrations or maximum allowable increases in pollutant concentrations as proposed in § 51.166(b)(23)(iv) and (v) and § 52.21(b)(23)(iv) and (v). Although these provisions are included in the definition of significant, they do not relate to the new provisions for HAP. Instead, they concern Class I issues, which we have not taken final action on.

VIII. Effective Date for Today's Requirements

As discussed above, today we are changing the existing NSR requirements in five ways.

- Providing a new method for determining baseline actual emissions
- Adopting the actual-to-projected-actual methodology for determining whether a major modification has occurred
- Allowing major stationary sources to comply with PALs to avoid having a significant emissions increase that triggers the requirements of the major NSR program
- Providing new applicability provisions for emissions units that are designated Clean Units
- Excluding PCPs from the definition of ''physical change or change in the method of operation''

Today's rules codify our longstanding policy for calculating the baseline actual emissions for EUSGUs, which is any consecutive 2 years in the past 5 years, or another more representative period. In today's final rules we are also including a new section that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules.

All of these changes will take effect in the Federal PSD program (codified at § 52.21) on March 3, 2003. This means that these rules will apply on March 3, 2003, in any area without an approved PSD program, for which we are the reviewing authority, or for which we have delegated our authority to issue permits to a State or local reviewing authority.

To be approvable under the SIP, State and local agency programs implementing part C (PSD permit program in § 51.166) or part D (nonattainment NSR permit program in § 51.165) must include today's changes as minimum program elements. State and local agencies should assure that any program changes under §§ 51.165 and 51.166 are consistently accounted for in other SIP planning measures. State and local agencies must adopt and submit revisions to their part 51 permitting programs implementing these minimum program elements no later than January 2, 2006. That is, for both nonattainment and attainment areas, the SIP revisions must be adopted and submitted within 3 years from today. The Act does not specify a date for submission of SIPs when we revise the PSD and NSR rules. We believe it is appropriate to establish a date analogous to the date for submission of new SIPs when a NAAQS is promulgated or revised. Under section 110(a)(1) of the Act, as amended in 1990, that date is 3 years from promulgation or revision of the NAAQS. Accordingly, we have established 3 years from today's revisions as the required date for submission of conforming SIP revisions. We have made conforming changes to the PSD regulations at § 51.166(a)(6)(i) to indicate that State and local agencies must adopt and submit plan revisions within 3 years after new amendments are published in the **Federal Register**.

In our 1996 proposed rule, we solicited comment on a new approach for implementing the applicability-related NSR improvements (*i.e.*, PALs, the Clean Unit provision, the PCP Exclusion, and provisions related to measuring emissions increases). We noted that the Agency in the past "has essentially required States to follow a single applicability methodology," but that "States could, of course, have a more stringent approach." 61 FR 38253. Instead of following this normal course, we proposed to establish the new applicability provisions as a "menu" of options. Under this approach, we would have allowed States to adopt into their NSR programs all, some, or none of the new provisions.

In today's final rule, we have decided not to implement the menu approach. We have opted instead to retain our longstanding approach of incorporating all of the new provisions into our "base" NSR program requirements, which are set forth in §§ 51.165, 51.166, and 52.24. The same provisions will be included in § 52.21, our own PSD permitting program. Our decision is based primarily on our belief that the NSR program will work better as a practical matter and will produce better environmental results if all five of the new applicability provisions are adopted and implemented. We and our stakeholders invested unprecedented amounts of time, energy, and resources in deciding how best to improve the NSR program. After well over a decade of sustained effort, we believe that we have found effective solutions to many of the program's most intractable problems. We hope that making the new provisions part of our base programs will provide incentive for these provisions to be adopted on a widespread basis.

Notably, even without the menu approach, State and local jurisdictions have significant freedom to customize their NSR programs. Ever since our current NSR regulations were adopted in 1980, we have taken the position that States may meet the requirements of part 51 "with different but equivalent regulations." 45 FR 52676. Several States have, indeed, implemented programs that work every bit as well as our own base programs, yet depart substantially from the basic framework established in our rules. A good example is Oregon, where the SIP-approved program requires all major sources to obtain plantwide permits not unlike the PALs that we are finalizing today. Oregon's program plainly illustrates that we have not implemented our base programs with a one-size-fits-all mentality and certainly do not have the goal of "preempting" State creativity or innovation.

Perhaps the biggest potential disadvantages to implementing the new applicability provisions as part of our base programs are the time and effort required to revise existing State programs and to have the revised programs approved as part of the SIP. For States that choose to adopt all of the new applicability provisions, we expect that the SIP approval process will be expeditious. Of course, the review and approval process will be more complicated for States that choose to adopt a program that differs from our base programs. For example, if a State decides it does not want to implement any of the new applicability provisions, that State will need to show that its existing program is at least as stringent as our revised base program. It would be impossible for us to plan ahead for all of the possible variations that States might ultimately elect to pursue. We will, however, reach out to relevant stakeholders immediately after publication of these rules and try to develop streamlined methods for addressing common questions that may arise during the SIP approval process.

IX. Administrative Requirements

A. Executive Order 12866—Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified us that it considers this rule a "significant regulatory action." As such, this action was submitted to OMB for review.

B. Executive Order 13132—Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. While this final rule will result in some expenditures by the States, we expect those expenditures to be limited to $331,250 per year. This figure includes the small increase in the burden imposed upon reviewing authorities in order for them to revise the State's SIP. However, these revisions provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. Thus, Executive Order 13132 does not apply to this rule. Nevertheless, in the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, we specifically solicited comment on the proposed rule from State and local officials.

C. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' We believe that this final rule does not have tribal implications as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this rule.

EPA began considering potential revisions to the NSR rules in the early 1990's and proposed changes in 1996. The purpose of today's final rule is to add greater flexibility to the existing major NSR regulations. These changes will benefit both reviewing authorities and the regulated community by providing increased certainty as to when the requirements apply, and by providing alternative ways to comply with the requirements. Taken as a whole, today's final rule should result in no added burden or compliance costs and should not substantially change the level of environmental performance achieved under the previous rules.

We anticipate that initially these changes will result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, as well as other small increases in burden discussed under ''Paperwork Reduction Act.'' Nevertheless, these revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In comparison, no tribal government currently has an approved tribal implementation plan (TIP) under the CAA to implement the NSR program. The Federal government is currently the NSR reviewing authority in Indian country, thus tribal governments should not experience added burden, nor should their laws be affected with respect to implementation of this rule. Additionally, although major stationary sources affected by today's final rule could be located in or near Indian country and/or be owned or operated by tribal governments, such sources would not incur additional costs or compliance burdens as a result of this rule. Instead, the only effect on such sources should be the benefit of the added certainty and flexibility provided by the rule.

We recognize the importance of including tribal consultation as part of the rulemaking process. Although we did not include specific consultation with tribal officials as part of our outreach process on this final rule, which was developed largely prior to issuance of Executive Order 13175 and which does not have tribal implications under Executive Order 13175, we will continue to consult with tribes on future rulemakings to assess and address tribal implications, and will work with tribes interested in seeking TIP approval to implement the NSR program to ensure consistency of tribal plans with this rule.

D. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children because we believe that this package as a whole will result in equal or better environmental protection than currently provided by the existing regulations, and do so in a more streamlined and effective manner.

E. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective or least burdensome alternative if the Administrator publishes with the final rule an explanation as to why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan.

The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Although initially these changes are expected to result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, as well as other small increases in burden discussed under ''Paperwork Reduction Act,'' these revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In addition, we believe the rule changes will actually reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Thus, today's rule is not subject to the requirements of sections 202 and 205 of the UMRA.

For the same reasons stated above, we have determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. Thus, today's rule is not subject to the requirements of section 203 of the UMRA.

F. Regulatory Flexibility Analysis

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) Any small business employing fewer than 500 employees; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, we have concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect, on all of the small entities subject to the rule.

A Regulatory Flexibility Act Screening Analysis (RFASA), developed as part of a 1994 draft Regulatory Impact Analysis (RIA) and incorporated into the September 1995 ICR renewal analysis, showed that the changes to the NSR program due to the 1990 CAA Amendments would not have an adverse impact on small entities. This analysis encompassed the entire universe of applicable major sources that were likely to also be small businesses (approximately 50 ''small business'' major sources). Because the administrative burden of the NSR program is the primary source of the NSR program's regulatory costs, the analysis estimated a negligible ''cost to sales'' (regulatory cost divided by the business category mean revenue) ratio for this source group. Currently, and as reported in the current ICR, there is no economic basis for a different conclusion.

We believe these rule changes will reduce the regulatory burden associated with the major NSR program for all sources, including all small businesses, by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. As a result, the program changes provided in the final rule are not expected to result in any increases in expenditure by any small entity.

We have therefore concluded that today's final rule will relieve regulatory burden for all small entities.

G. Paperwork Reduction Act

The information collection requirements in this rule will be contained in two different Information Collection Requests (ICRs).

The Office of Management and Budget (OMB) has approved the information collection requirements contained under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0003 (ICR 1230.10). The EPA prepared an ICR document (ICR No. 1230.10) extending the approval of the ICR for the promulgated NSR regulations on March 30, 2001. On October 29, 2001, OMB approved EPA's request for extension for 3 years until October 31, 2004. The OMB number for this approval is 2060–0003.

In addition to the existing ICR, the information collection requirements in this final rule have been submitted for approval to OMB under the requirements of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 2074.01), and a copy may be obtained from Susan Auby, U.S. Environmental Protection Agency, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0001, by e-mail at *auby.susan@epa.gov,* or by calling (202) 566–1672. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.* The information requirements included in ICR No. 2074.01 are not effective until OMB approves them.

The information that ICR No. 2074.01 covers is required for the submittal of a complete permit application for the construction or modification of all major new stationary sources of pollutants in attainment and nonattainment areas, as well as for applicable minor stationary sources of pollutants. This information collection is necessary for the proper performance of EPA's functions, has practical utility, and is not unnecessarily duplicative of information we otherwise can reasonably access. We have reduced, to the extent practicable and appropriate, the burden on persons providing the information to or for EPA.

According to ICR No. 2074.01, as a result of the rule changes, the total 3-year burden change of the revised collection is estimated at about 219,741 hours at a total cost of $7.7 million. The annual burden change to industry is about 64,287 hours at a cost of $2.2 million. The annual burden change to reviewing agencies is about 8,960 hours at a cost of $331,520. The total annual respondent change is 73,247 hours for a total respondent change in cost of $2.6 million. These costs changes are based upon 62 PSD and 123 NSR non-utility sources (185 total); and 85 PSD and 169 NSR (254 total) sources, including utilities. For the number of respondent reviewing authorities, the analysis uses the 112 reviewing authorities count used by other permitting ICRs for the one-time tasks (for example, SIP revisions) and the appropriate source count for individual permit-related items (for example, attending pre-application meetings with the source). There is only one Federal source listed in the ICR.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purpose of responding to the information collection; adjust existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. We will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the *Paperwork Reduction Act* (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

H. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Pub. L. 104–113, 12(d) (15 U.S.C. 272 *note*) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical.

Voluntary consensus standards are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. This final rule does not create new requirements but, rather, revises an existing permitting program by providing a series of program options that affected facilities may choose to adopt. These options will reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Therefore, EPA did not consider the use of any voluntary consensus standards.

I. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). Nonetheless, the Agency has decided to provide an effective date that is 60 days after publication in the **Federal Register**. This rule will be effective March 3, 2003.

J. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Today's rule improves the ability of sources to undertake pollution prevention or energy efficiency projects, switch to less polluting fuels or raw materials, maintain the reliability of production facilities, and effectively utilize and improve existing capacity. The rule also includes a number of provisions to streamline administrative and permitting processes so that facilities can quickly accommodate changes in supply and demand. The regulations provide several alternatives that are specifically designed to reduce administrative burden for sources that use pollution prevention or energy efficient projects.

X. Statutory Authority

The statutory authority for this action is provided by sections 101, 112, 114, 116, and 301 of the Act as amended (42 U.S.C. 7401, 7412, 7414, 7416, and 7601). This rulemaking is also subject to section 307(d) of the Act (42 U.S.C. 7407(d)).

XI. Judicial Review

Under section 307(b)(1) of the Act, judicial review of this final rule is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 3, 2003. Any such judicial review is limited to only those objections that are raised with reasonable specificity in timely comments. Under section 307(b)(2) of the Act, the requirements that are the subject of this final rule may not be challenged later in civil or criminal proceedings brought by us to enforce these requirements.

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practices and procedures, Air pollution control, BACT, Baseline emissions, Carbon monoxide, Clean Units, Hydrocarbons, Intergovernmental relations, LAER, Lead, Major modifications, Nitrogen oxides, Ozone, Particular matter, Plantwide applicability limitations, Pollution control projects, Sulfur oxides.

40 CFR Part 52

Environmental protection, Administrative practices and procedures, Air pollution control, BACT, Baseline emissions, Carbon monoxide, Clean Units, Hydrocarbons, Intergovernmental relations, LAER, Lead, Major modifications, Nitrogen oxides, Ozone, Particulate matter, Plantwide applicability limitations, Pollution control projects, Sulfur oxides.

Dated: November 22, 2002.

Christine Todd Whitman,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51— [Amended]

1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401—7671 q.

Subpart I— [Amended]

2. In 40 CFR 51.165(a)(1)(i), remove the words ''any air pollutant subject to regulation under the Act,'' and add, in their place, the words ''a regulated NSR pollutant.''

3. In addition to the amendments set forth above, in 40 CFR 51.165 (a)(1)(iv)(A)(*1*), remove the words ''pollutant subject to regulation under the Act'' and add, in their place, the words ''regulated NSR pollutant.''

4. In addition to the amendments set forth above, § 51.165 is amended:

a. By revising the introductory text in paragraph (a).

b. By revising paragraphs (a)(1)(v)(A) and (B).

c. By revising paragraph (a)(1)(v)(C)(*8*).

d. By adding paragraph (a)(1)(v)(D).

e. By revising paragraph (a)(1)(vi)(A).

f. By revising paragraph (a)(1)(vi)(C).

g. By revising paragraph (a)(1)(vi)(E)(*2*).

h. By revising paragraph (a)(1)(vi)(E)(*4*).

i. By adding paragraph (a)(1)(vi)(E)(*5*).

j. By adding paragraph (a)(1)(vi)(G).

k. By revising paragraph (a)(1)(vii).

l. By revising paragraph (a)(1)(xii).
m. By revising the introductory text in paragraph (a)(1)(xiii).
n. By revising paragraph (a)(1)(xviii).
o. By reserving paragraph (a)(1)(xxi).
p. By revising paragraph (a)(1)(xxv).
q. By adding paragraphs (a)(1)(xxvi) through (xlii).
r. By revising paragraph (a)(2).
s. By adding paragraphs (a)(3)(ii)(H) through (J).
t. By adding paragraphs (a)(6) through (7).
u. By adding paragraphs (c) through (g).

The revisions and additions read as follows:

§ 51.165 Permit requirements.

(a) State Implementation Plan and Tribal Implementation Plan provisions satisfying sections 172(c)(5) and 173 of the Act shall meet the following conditions:

(1) * * *

(v) * * *

(A) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in:

(*1*) A significant emissions increase of a regulated NSR pollutant (as defined in paragraph (a)(1)(xxxvii) of this section); and

(*2*) A significant net emissions increase of that pollutant from the major stationary source.

(B) Any significant emissions increase (as defined in paragraph (a)(1)(xxvii) of this section) from any emissions units or net emissions increase (as defined in paragraph (a)(1)(vi) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(C) * * *

(*8*) The addition, replacement, or use of a PCP, as defined in paragraph (a)(1)(xxv) of this section, at an existing emissions unit meeting the requirements of paragraph (e) of this section. A replacement control technology must provide more effective emissions control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(D) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (f) of this section for a PAL for that pollutant. Instead, the definition at paragraph (f)(2)(viii) of this section shall apply.

(vi)(A) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*1*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(ii) of this section; and

(*2*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (a)(1)(vi)(A)(*2*) shall be determined as provided in paragraph (a)(1)(xxxv) of this section, except that paragraphs (a)(1)(xxxv)(A)(*3*) and (a)(1)(xxxv)(B)(*4*) of this section shall not apply.

* * * * *

(C) An increase or decrease in actual emissions is creditable only if:

(*1*) It occurs within a reasonable period to be specified by the reviewing authority; and

(*2*) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*3*) The increase or decrease in emissions did not occur at a Clean Unit, except as provided in paragraphs (c)(8) and (d)(10) of this section.

* * * * *

(E) * * *

(*2*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins; and

* * * * *

(*4*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*5*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under 40 CFR 52.21(y) or under regulations approved pursuant to paragraph (d) of this section or § 51.166(u). That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the Clean Unit designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emissions reductions that were not relied upon in a PCP excluded pursuant to paragraph (e) of this section or for a Clean Unit designation are creditable to the extent they meet the requirements in paragraphs (e)(6)(iv) of this section for the PCP and paragraphs (c)(8) or (d)(10) of this section for a Clean Unit.

* * * * *

(G) Paragraph (a)(1)(xii)(B) of this section shall not apply for determining creditable increases and decreases or after a change.

* * * * *

(vii) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric steam generating unit as defined in paragraph (a)(1)(xx) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (a)(1)(vii)(A) and (B) of this section.

(A) A new emissions unit is any emissions unit which is (or will be) newly constructed and which has existed for less than 2 years from the date such emissions unit first operated.

(B) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (a)(1)(vii)(A) of this section.

* * * * *

(xii)(A) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (a)(1)(xii)(B) through (D) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (f) of this section. Instead, paragraphs (a)(1)(xxviii) and (xxxv) of this section shall apply for those purposes.

(B) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(C) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(D) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(xiii) *Lowest achievable emission rate (LAER)* means, for any source, the more stringent rate of emissions based on the following: * * *

* * * * *

(xviii) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(xxi) [Reserved]

* * * * *

(xxv) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (a)(1)(xxvi) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (a)(1)(xxv)(A) through (F) of this section are presumed to be environmentally beneficial pursuant to paragraph (e)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (e)(2) and (e)(5) of this section.

(A) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(B) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(C) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(D) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(E) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*1*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*2*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*3*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*4*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*5*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(F) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP), including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (a)(1)(xxv)(F)(*1*) and (*2*) of this section.

(*1*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*2*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (a)(1)(xxv)(F)(*2*)(*i*) through (*iv*) of this section.

(*i*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*ii*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*iii*) Calculate the projected ODP-weighted amount by multiplying the projected future annual usage of the new substance by its ODP.

(*iv*) If the value calculated in paragraph (a)(1)(xxv)(F)(*2*)(*ii*) of this section is more than the value calculated in paragraph (a)(1)(xxv)(F)(*2*)(*iii*) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(xxvi) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(xxvii) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (a)(1)(x) of this section) for that pollutant.

(xxviii)(A) *Projected actual emissions* means, the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(B) In determining the projected actual emissions under paragraph (a)(1)(xxviii)(A) of this section before beginning actual construction, the owner or operator of the major stationary source:

(*1*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan; and

(*2*) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; and

(*3*) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (a)(1)(xxxv) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

(*4*) In lieu of using the method set out in paragraphs (a)(1)(xxviii)(B)(*1*) through (*3*) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (a)(1)(iii) of this section.

(xxix) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, that is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved by the Administrator in accordance with paragraph (c) of this section; or any emissions unit that has been designated by a reviewing authority as a Clean Unit, based on the criteria in paragraphs (d)(3)(i) through (iv) of this section, using a plan-approved permitting process; or any emissions unit that has been designated as a Clean Unit by the Administrator in accordance with § 52.21(y)(3)(i) through (iv) of this chapter.

(xxx) *Nonattainment major new source review (NSR) program* means a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of this section, or a program that implements part 51, appendix S, Sections I through VI of this chapter. Any permit issued under such a program is a major NSR permit.

(xxxi) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(xxxii) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(xxxiii) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(xxxiv) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(xxxv) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (a)(1)(xxxv)(A) through (D) of this section.

(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*1*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*2*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

(*3*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

(*4*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (a)(1)(xxxv)(A)(*2*) of this section.

(B) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority for a permit required either under this section or under a plan approved by the Administrator, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*1*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*2*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*3*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of paragraph (a)(3)(ii)(G) of this section.

(*4*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*5*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (a)(1)(xxxv)(B)(*2*) and (*3*) of this section.

(C) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(D) For a PAL for a major stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (a)(1)(xxxv)(A) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (a)(1)(xxxv)(B) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (a)(1)(xxxv)(C) of this section.

(xxxvi) [Reserved]

(xxxvii) *Regulated NSR pollutant,* for purposes of this section, means the following:

(A) Nitrogen oxides or any volatile organic compounds;

(B) Any pollutant for which a national ambient air quality standard has been promulgated; or

(C) Any pollutant that is a constituent or precursor of a general pollutant listed under paragraphs (a)(1)(xxxvii)(A) or (B) of this section, provided that a constituent or precursor pollutant may only be regulated under NSR as part of regulation of the general pollutant.

(xxxviii) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under this section and § 51.166, or the Administrator in the case of EPA-implemented permit programs under § 52.21.

(xxxix) *Project* means a physical change in, or change in the method of operation of, an existing major stationary source.

(XL) *Best available control technology (BACT)* means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR part 60 or 61. If the reviewing authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

(XLi) *Prevention of Significant Deterioration (PSD) permit* means any permit that is issued under a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of § 51.166 of this chapter, or under the program in § 52.21 of this chapter.

(XLii) *Federal Land Manager* means, with respect to any lands in the United States, the Secretary of the department with authority over such lands.

(2) *Applicability procedures.* (i) Each plan shall adopt a preconstruction review program to satisfy the requirements of sections 172(c)(5) and 173 of the Act for any area designated nonattainment for any national ambient air quality standard under subpart C of 40 CFR part 81. Such a program shall apply to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment under section 107(d)(1)(A)(i) of the Act, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(ii) Each plan shall use the specific provisions of paragraphs (a)(2)(ii)(A) through (F) of this section. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(2)(ii)(A) through (F) of this section.

(A) Except as otherwise provided in paragraphs (a)(2)(iii) and (iv) of this section, and consistent with the definition of major modification contained in paragraph (a)(1)(v)(A) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (a)(1)(xxvii) of this section), and a significant net emissions increase (as defined in paragraphs (a)(1)(vi) and (x) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(B) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(ii)(C) through (F) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (a)(1)(vi) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(C) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (a)(1)(xxviii) of this section) and the baseline actual emissions (as defined in paragraphs (a)(1)(xxxv)(A) and (B) of this section, as applicable), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(D) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (a)(1)(iii) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (a)(1)(xxxv)(C) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(E) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(F) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(ii)(C) through (E) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(ii)(C) of this section for the existing unit and using the method specified in paragraph (a)(2)(ii)(E) of this section for the Clean Unit.

(iii) The plan shall require that for any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with requirements under paragraph (f) of this section.

(iv) The plan shall require that an owner or operator undertaking a PCP (as defined in paragraph (a)(1)(xxv) of this section) shall comply with the requirements under paragraph (e) of this section.

(3) * * *

(ii) * * *

(H) Decreases in actual emissions resulting from the installation of add-on control technology or application of pollution prevention measures that were relied upon in designating an emissions unit as a Clean Unit or a project as a PCP cannot be used as offsets.

(I) Decreases in actual emissions occurring at a Clean Unit cannot be used as offsets, except as provided in paragraphs (c)(8) and (d)(10) of this section. Similarly, decreases in actual emissions occurring at a PCP cannot be used as offsets, except as provided in paragraph (e)(6)(iv) of this section.

(J) The total tonnage of increased emissions, in tons per year, resulting from a major modification that must be offset in accordance with section 173 of the Act shall be determined by summing the difference between the allowable emissions after the modification (as defined by paragraph (a)(1)(xi) of this section) and the actual emissions before the modification (as defined in paragraph (a)(1)(xii) of this section) for each emissions unit.

* * * * *

(6) Each plan shall provide that the following specific provisions apply to projects at existing emissions units at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (a)(1)(xxviii)(B)(*1*) through (*3*) of this section for calculating projected actual emissions. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(6)(i) through (v) of this section.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(A) A description of the project;

(B) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (a)(1)(xxviii)(B)(*3*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (a)(6)(i) of this section to the reviewing authority. Nothing in this paragraph (a)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the reviewing authority before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions units identified in paragraph (a)(6)(i)(B) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority within 60 days after the end of each year during which records must be generated under paragraph (a)(6)(iii) of this section setting out the unit's annual emissions during the year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority if the annual emissions, in tons per year, from the project identified in paragraph (a)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (a)(6)(i)(C) of this section, by a significant amount (as defined in paragraph (a)(1)(x) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (a)(6)(i)(C) of this section. Such report shall be submitted to the reviewing authority within 60 days after the end of such year. The report shall contain the following:

(A) The name, address and telephone number of the major stationary source;

(B) The annual emissions as calculated pursuant to paragraph (a)(6)(iii) of this section; and

(C) Any other information that the owner or operator wishes to include in the report (*e.g.*, an explanation as to why the emissions differ from the preconstruction projection).

(7) Each plan shall provide that the owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (a)(6) of this section available for review upon a request for inspection by the reviewing authority or the general public pursuant to the requirements contained in § 70.4(b)(3)(viii) of this chapter.

* * * * *

(c) *Clean Unit Test for emissions units that are subject to LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (c)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (c) apply to any emissions unit for which the reviewing authority has issued a major NSR permit within the past 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (c)(2)(i) through (v) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (c)(4) of this section) and before the expiration date (as determined in accordance with paragraph (c)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with LAER and the project would not alter any physical or operational characteristics that formed the basis for the LAER determination as specified in paragraph (c)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with LAER or the project would alter any physical or operational characteristics that formed the basis for the LAER determination as specified in paragraph (c)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit requalifies as a Clean Unit pursuant to paragraph (c)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(ii)(A) through (D) and paragraph (a)(2)(ii)(F) of this section as if the emissions unit is not a Clean Unit.

(v) *Certain Emissions Units with PSD permits.* For emissions units that meet the requirements of paragraphs (c)(2)(v)(A) and (B) of this section, the BACT level of emissions reductions and/or work practice requirements shall satisfy the requirement for LAER in meeting the requirements for Clean Units under paragraphs (c)(3) through (8) of this section. For these emissions units, all requirements for the LAER determination under paragraphs (c)(2)(ii) and (iii) of this section shall also apply to the BACT permit terms and conditions. In addition, the requirements of paragraph (c)(7)(i)(B) of this section do not apply to emissions units that qualify for Clean Unit status under this paragraph (c)(2)(v).

(A) The emissions unit must have received a PSD permit within the last 10 years and such permit must require the emissions unit to comply with BACT.

(B) The emissions unit must be located in an area that was redesignated as nonattainment for the relevant pollutant(s) after issuance of the PSD permit and before the effective date of the Clean Unit Test provisions in the area.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit automatically qualifies as a Clean Unit when the unit meets the criteria in paragraphs (c)(3)(i) and (ii) of this section. After the original Clean Unit designation expires in accordance with paragraph (c)(5) of this section or is lost pursuant to paragraph (c)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (c)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (d) of this section. To re-qualify as a Clean Unit under paragraph (c)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable nonattainment major NSR program and meet all the criteria in paragraph (c)(3)(iii) of this section. Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the past 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of an air pollution control technology (which includes pollution prevention as defined under paragraph (a)(1)(xxvi) of this section or work practices) that meets both the following requirements in paragraphs (c)(3)(ii)(A) and (B) of this section.

(A) The control technology achieves the LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for Clean Unit designation if the LAER determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(B) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day LAER, and the emissions unit must meet the requirements in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (c)(4)(i) or (c)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing a new control technology to meet current-day LAER.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the plan and become effective for the State in which the unit is located.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (c)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day LAER.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (c)(3)(i) and (ii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining Clean Unit designation in paragraph (c)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (c)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit Designation in paragraph (c)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions in paragraphs (c)(6)(i) through (vi) of this section related to the Clean Unit.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this Clean Unit designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.*, because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with the LAER, and any physical or operational characteristics that formed the basis for the LAER determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (c)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (c)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (c)(7)(i) through (iii) of this section. This paragraph (c)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the LAER that is recorded in the major NSR permit, and subsequently reflected in the title V permit.

(A) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the LAER determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(B) The Clean Unit may not emit above a level that has been offset.

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Offsets and netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), or be used for generating offsets unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then, the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(d) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (d)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (d) apply to emissions units which do not qualify as Clean Units under paragraph (c) of this section, but which are achieving a level of emissions control comparable to LAER, as determined by the reviewing authority in accordance with this paragraph (d).

(2) *General provisions for Clean Units.* The provisions in paragraphs (d)(2)(i) through (iv) of this section apply to a Clean Unit (designated under this paragraph (d)).

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (d)(5) of this section) and before the expiration date (as determined in accordance with paragraph (d)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (d)(4) of this section) to be comparable to LAER, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER as specified in paragraph (d)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (d)(4) of this section) to be comparable to LAER, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER as specified in paragraph (d)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (d)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(ii)(A) through (D) and paragraph (a)(2)(ii)(F) of this section as if the emissions unit were never a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (d)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (d)(6) of this section or is lost pursuant to paragraph (d)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (d)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (c) of this section. To re-qualify as a Clean Unit under paragraph (d)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (d)(7) and (8) of this section and meet all the criteria in paragraph (d)(3)(iv) of this section. The reviewing authority will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (a)(1)(xxvi) of this section or work practices) that meets both the following requirements in paragraphs (d)(3)(i)(A) and (B) of this section.

(A) The owner or operator has demonstrated that the emissions unit's control technology is comparable to LAER according to the requirements of paragraph (d)(4) of this section. However, the emissions unit is not eligible for the Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.*, if the LAER determinations to which it is compared have resulted in a determination that no control measures are required).

(B) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The reviewing authority must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before the effective date of plan requirements to implement the requirements of this paragraph (d)(3)(iii). However, for such emissions units, the owner or operator must apply for the Clean Unit designation within 2 years after the plan requirements become effective. For technologies installed after the plan requirements become effective, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (d)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day LAER, and the emissions unit must meet the requirements in paragraphs (d)(3)(i)(A) and (d)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to LAER.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to LAER for purposes of paragraph (d)(3)(i) of this section according to either paragraph (d)(4)(i) or (ii) of this section. Paragraph (d)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous LAER determinations.* The administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to LAER if it achieves an emission limitation that is at least as stringent as any one of the five best-performing similar sources for which a LAER determination has been made within the preceding 5 years, and for which information has been entered into the RBLC. The reviewing authority shall also compare this presumption to any additional LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to LAER is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as LAER. In addition, any other person may present evidence related to whether the control technology is substantially as effective as LAER during the public participation process required under paragraph (d)(7) of this section. The reviewing authority shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as LAER.

(iii) *Time of comparison.*

(A) *Emissions units with control technologies that are installed before the effective date of plan requirements implementing this paragraph.* The owner or operator of an emissions unit whose control technology is installed before the effective date of plan requirements implementing this paragraph (d) may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the LAER requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day LAER requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (d)(6) of this section.

(B) *Emissions units with control technologies that are installed after the effective date of plan requirements implementing this paragraph.* The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day LAER requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major modification) is the date that the permit required by paragraph (d)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the LAER requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (d)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (d)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The reviewing authority shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (d)(8).

(8) *Required permit content.* The permit required by paragraph (d)(7) of this section shall include the terms and conditions set forth in paragraphs (d)(8)(i) through (vi) of this section. Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to LAER, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (d)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (d)(9) of this section.

(9) *Maintaining Clean Unit designation.* To maintain Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (d)(9)(i) through (v) of this section. This paragraph (d)(9) applies independently to each pollutant for which the reviewing authority has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to LAER.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to LAER (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) The Clean Unit may not emit above a level that has been offset.

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Offsets and Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), or be used for generating offsets unless such use occurs before the effective date of plan requirements adopted to implement this paragraph (d) or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of

determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (c)(2)(iii) and (d)(2)(iii) of this section, it must re-qualify under the requirements that are currently applicable.

(e) *PCP exclusion procedural requirements.* Each plan shall include provisions for PCPs equivalent to those contained in paragraphs (e)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the reviewing authority if the project is listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, or if the project is not listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the reviewing authority consistent with the requirements in paragraph (e)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (e)(2) of this section, and the notice or permit application must contain the information required in paragraph (e)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements in paragraphs (e)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emission reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (a)(1)(xxv)(A) through (F) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the reviewing authority, the owner or operator must include, at a minimum, the information listed in paragraphs (e)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(2)(ii) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (e)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (e)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (e)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant which will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the reviewing authority (unless otherwise prohibited under requirements of the applicable plan). The owner or operator shall respond to any requests by its reviewing authority for additional information that the reviewing authority determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, the project must be approved by the reviewing authority and recorded in a plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The reviewing authority must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (e)(6)(i) through (iii) of this section.

(i) *General duty.* The owner or operator must operate the PCP in a manner consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (e)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (e)(3) of this section, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (e)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of emission reduction credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase, or be used for generating offsets, unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation). The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(f) *Actuals PALs.* The plan shall provide for PALs according to the provisions in paragraphs (f)(1) through (15) of this section.

(1) *Applicability.*

(i) The reviewing authority may approve the use of an actuals PAL for any existing major stationary source (except as provided in paragraph (f)(1)(ii) of this section) if the PAL meets the requirements in paragraphs (f)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (f) of this section.

(ii) The reviewing authority shall not allow an actuals PAL for VOC or NO_X for any major stationary source located in an extreme ozone nonattainment area.

(iii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (f)(1) through (15) of this section, and complies with the PAL permit:

(A) Is not a major modification for the PAL pollutant;

(B) Does not have to be approved through the plan's nonattainment major NSR program; and

(C) Is not subject to the provisions in paragraph (a)(5)(ii) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the nonattainment major NSR program).

(iv) Except as provided under paragraph (f)(1)(iii)(C) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* The plan shall use the definitions in paragraphs (f)(2)(i) through (xi) of this section for the purpose of developing and implementing regulations that authorize the use of actuals PALs consistent with paragraphs (f)(1) through (15) of this section. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (a)(1) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (a)(1)(xxxv) of this section) of all emissions units (as defined in paragraph (a)(1)(vii) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (a)(1)(xi) of this section, except as this definition is modified according to paragraphs (f)(2)(ii)(A) through (B) of this section.

(A) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(B) An emissions unit's potential to emit shall be determined using the definition in paragraph (a)(1)(iii) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (a)(1)(x) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(A) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(B) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (f)(1) through (f)(15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit which is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (a)(1)(v) and (vi) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the plan, or the title V permit issued by the reviewing authority that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (a)(1)(x) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (f)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information to the reviewing authority for approval:

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (f)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The plan allows the reviewing authority to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (f)(4)(i)(A) through (G) of this section are met.

(A) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(B) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (f)(5) of this section.

(C) The PAL permit shall contain all the requirements of paragraph (f)(7) of this section.

(D) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(E) Each PAL shall regulate emissions of only one pollutant.

(F) Each PAL shall have a PAL effective period of 10 years.

(G) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (f)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant, which occur during the PAL effective period, creditable as decreases for purposes of offsets under paragraph (a)(3)(ii) of this section unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirement for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The reviewing authority must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (a)(1)(xxxv) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (a)(1)(x) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The plan shall require that the PAL permit contain, at a minimum, the information in paragraphs (f)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (f)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the reviewing authority.

(iv) A requirement that emission calculations for compliance purposes include emissions from startups, shutdowns and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (f)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (f)(13)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (f)(12) of this section.

(viii) A requirement to retain the records required under paragraph (f)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (f)(14) of this section by the required deadlines.

(x) Any other requirements that the reviewing authority deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The plan shall require the information in paragraphs (f)(8)(i) and (ii) of this section.

(i) *PAL effective period.* The reviewing authority shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(A) During the PAL effective period, the plan shall require the reviewing authority to reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL.

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under paragraph (a)(3)(ii) of this section.

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (f)(11) of this section.

(B) The plan shall provide the reviewing authority discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date.

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the plan.

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(C) Except for the permit reopening in paragraph (f)(8)(ii)(A)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of paragraph (f)(5) of this section.

(9) *Expiration of a PAL.* Any PAL which is not renewed in accordance with the procedures in paragraph (f)(10) of this section shall expire at the end of the PAL effective period, and the requirements in paragraphs (f)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (f)(9)(i)(A) through (B) of this section.

(A) Within the time frame specified for PAL renewals in paragraph (f)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the reviewing authority) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (f)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(B) The reviewing authority shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the reviewing authority determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The reviewing authority may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the reviewing authority issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (f)(9)(i)(A) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to the nonattainment major NSR requirements if such change meets the definition of major modification in paragraph (a)(1)(v) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (a)(5)(ii) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (f)(1)(iii)(C) of this section.

(10) *Renewal of a PAL.*

(i) The reviewing authority shall follow the procedures specified in paragraph (f)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the reviewing authority.

(ii) *Application deadline.* The plan shall require that a major stationary source owner or operator shall submit a timely application to the reviewing authority to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (f)(10)(iii)(A) through (D) of this section.

(A) The information required in paragraphs (f)(3)(i) through (iii) of this section.

(B) A proposed PAL level.

(C) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(D) Any other information the owner or operator wishes the reviewing authority to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the reviewing authority shall consider the options outlined in paragraphs (f)(10)(iv)(A) and (B) of this section. However, in no case may any such adjustment fail to comply with paragraph (f)(10)(iv)(C) of this section.

(A) If the emissions level calculated in accordance with paragraph (f)(6) of this section is equal to or greater than 80 percent of the PAL level, the reviewing authority may renew the PAL at the same level without considering the factors set forth in paragraph (f)(10)(iv)(B) of this section; or

(B) The reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale.

(C) Notwithstanding paragraphs (f)(10)(iv)(A) and (B) of this section,

(*1*) If the potential to emit of the major stationary source is less than the PAL, the reviewing authority shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The reviewing authority shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (f)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the reviewing authority has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The plan shall require that the reviewing authority may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (f)(11)(i)(A) through (D) of this section.

(A) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(B) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(C) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (f)(11)(i)(A) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the nonattainment major NSR program process (for example, LAER), even though they have also become subject to the PAL or continue to be subject to the PAL.

(D) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The reviewing authority shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (f)(11)(i)(B)), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (f)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) General Requirements.

(A) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(B) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (f)(12)(ii)(A) through (D) of this section and must be approved by the reviewing authority.

(C) Notwithstanding paragraph (f)(12)(i)(B) of this section, you may also employ an alternative monitoring approach that meets paragraph (f)(12)(i)(A) of this section if approved by the reviewing authority.

(D) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum Performance Requirements for Approved Monitoring Approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (f)(12)(iii) through (ix) of this section:

(A) Mass balance calculations for activities using coatings or solvents;

(B) CEMS;

(C) CPMS or PEMS; and

(D) Emission Factors.

(iii) Mass Balance Calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(A) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(B) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(C) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the reviewing authority determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(A) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(B) CEMS must sample, analyze and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(A) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(B) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the reviewing authority, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(A) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(B) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(C) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (f)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the reviewing authority shall, at the time of permit issuance:

(A) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(B) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the reviewing authority. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (f) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus 5 years:

(A) A copy of the PAL permit application and any applications for revisions to the PAL; and

(B) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the reviewing authority in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (f)(14)(i) through (iii).

(i) Semi-Annual Report. The semi-annual report shall be submitted to the reviewing authority within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (f)(14)(i)(A) through (G) of this section.

(A) The identification of owner and operator and the permit number.

(B) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (f)(13)(i) of this section.

(C) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(D) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(E) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(F) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by paragraph (f)(12)(vii) of this section.

(G) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) Deviation report. The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(A) The identification of owner and operator and the permit number;

(B) The PAL requirement that experienced the deviation or that was exceeded;

(C) Emissions resulting from the deviation or the exceedance; and

(D) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) Re-validation results. The owner or operator shall submit to the reviewing authority the results of any re-validation test or method within 3 months after completion of such test or method.

(15) *Transition requirements.*

(i) No reviewing authority may issue a PAL that does not comply with the requirements in paragraphs (f)(1) through (15) of this section after the Administrator has approved regulations incorporating these requirements into a plan.

(ii) The reviewing authority may supersede any PAL which was established prior to the date of approval of the plan by the Administrator with a PAL that complies with the requirements of paragraphs (f)(1) through (15) of this section.

(g) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

5. In 40 CFR 51.166(b)(1)(i)(*b*) and (b)(5), remove the words ''any air pollutant subject to regulation under the Act,'' and add, in their place, the words ''a regulated NSR pollutant.''

6. In addition to the amendments set forth above, section 51.166 is amended:

a. By revising paragraph (a)(1).

b. By revising paragraph (a)(6)(i).

c. By adding paragraph (a)(7).

d. By revising paragraphs (b)(2)(i) and (ii).

e. By revising paragraph (b)(2)(iii)(*h*).

f. By adding paragraph (b)(2)(iv).

g. By revising paragraph (b)(3)(i).

h. By revising paragraphs (b)(3)(iii) and (iv).

i. By revising paragraphs (b)(3)(vi)(*b*) and (*c*).

j. By adding paragraph (b)(3)(vi)(*d*).

k. By adding paragraph (b)(3)(viii).

l. By revising paragraphs (b)(7) and (8).

m. By revising paragraph (b)(13).

n. By revising paragraph (b)(21).

o. By removing the following from paragraph (b)(23)(i): Asbestos: 0.007 tpy; Beryllium: 0.0004 tpy; Mercury: 0.1 tpy; and Vinyl Chloride: 1 tpy.

p. By revising paragraph (b)(31).

q. By reserving paragraph (b)(32).

r. By adding paragraphs (b)(38) through (52).

s. By revising the introductory text of paragraph (i).

t. By removing paragraphs (i)(1) through (3).

u. By re-designating paragraphs (i)(4) through (12) as paragraphs (i)(1) through (9).

v. By revising newly redesignated paragraphs (i)(5)(i)(*g*) through (*j*).

w. By removing newly redesignated paragraphs (i)(5)(i)(*k*) through (*m*).

x. By adding paragraphs (r)(3) through (7).

y. By adding paragraphs (t) through (x).

7. In addition to the amendments set forth above, in 40 CFR 51.166, remove the words ''pollutant subject to regulation under the Act'' and add, in their place, the words ''a regulated NSR pollutant'' in the following places:

a. (b)(1)(i)(*a*);

c. (b)(12);

d. (b)(23)(ii);

e. newly redesignated (i)(4); and

f. (j)(2) and (3).

The revisions and additions read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

(a)(1) *Plan requirements*. In accordance with the policy of section 101(b)(1) of the Act and the purposes of section 160 of the Act, each applicable State Implementation Plan and each applicable Tribal Implementation Plan shall contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality.

* * * * *

(6) * * *

(i) Any State required to revise its implementation plan by reason of an amendment to this section, including any amendment adopted simultaneously with this paragraph (a)(6)(i), shall adopt and submit such plan revision to the Administrator for approval no later than three years after such amendment is published in the **Federal Register**.

* * * * *

(7) *Applicability*. Each plan shall contain procedures that incorporate the requirements in paragraphs (a)(7)(i) through (vi) of this section.

(i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

(iii) No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements.

(iv) Each plan shall use the specific provisions of paragraphs (a)(7)(iv)(*a*) through (*f*) of this section. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(7)(iv)(*a*) through (*f*) of this section.

(*a*) Except as otherwise provided in paragraphs (a)(7)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (b)(39) of this section), and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(*b*) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(7)(iv)(*c*) through (*f*) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(*c*) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(40) of this section) and the baseline actual emissions (as defined in paragraphs (b)(47)(i) and (ii) of this section) for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(47)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*e*) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(7)(iv)(*c*) through (*e*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(7)(iv)(*c*) of this section for the existing unit and determined using the method specified in paragraph (a)(7)(iv)(*e*) of this section for the Clean Unit.

(v) The plan shall require that for any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with requirements under paragraph (w) of this section.

(vi) The plan shall require that an owner or operator undertaking a PCP (as defined in paragraph (b)(31) of this section) shall comply with the requirements under paragraph (v) of this section.

* * * * *

(b) * * *

(2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(39) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(49) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(ii) Any significant emissions increase (as defined at paragraph (b)(39) of this section) from any emissions units or net emissions increase (as defined at paragraph (b)(3) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) * * *

(*h*) The addition, replacement, or use of a PCP, as defined in paragraph (b)(31) of this section, at an existing emissions unit meeting the requirements of paragraph (v) of this section. A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(iv) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (w) of this section for a PAL for that pollutant. Instead, the definition at paragraph (w)(2)(viii) of this section shall apply.

(3)(i) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*a*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(7)(iv) of this section; and

(*b*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(*b*) shall be determined as provided in paragraph (b)(47), except that paragraphs (b)(47)(i)(*c*) and (b)(47)(ii)(*d*) of this section shall not apply.

* * * * *

(iii) An increase or decrease in actual emissions is creditable only if:

(*a*) It occurs within a reasonable period (to be specified by the reviewing authority); and

(*b*) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*c*) The increase or decrease in emissions did not occur at a Clean Unit, except as provided in paragraphs (t)(8) and (u)(10) of this section.

(iv) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

* * * * *

(vi) * * *

(*b*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins;

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*d*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under § 52.21(y) or under regulations approved pursuant to paragraph (u) of this section or § 51.165(d). That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the Clean Unit designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emissions reductions that were not relied upon in a PCP excluded pursuant to paragraph (v) of this section or for the Clean Unit designation are creditable to the extent they meet the requirements in paragraph (v)(6)(iv) of this section for the PCP and paragraph (t)(8) or (u)(10) of this section for a Clean Unit.

* * * * *

(viii) Paragraph (b)(21)(ii) of this section shall not apply for determining creditable increases and decreases.

* * * * *

(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(30) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section.

(8) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(13)(i) *Baseline concentration* means that ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(*a*) The actual emissions, as defined in paragraph (b)(21) of this section, representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph (b)(13)(ii) of this section;

(*b*) The allowable emissions of major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date; and

(*b*) Actual emissions increases and decreases, as defined in paragraph (b)(21) of this section, at any stationary source occurring after the minor source baseline date.

* * * * *

(21)(i) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii) through (iv) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (w) of this section. Instead, paragraphs (b)(40) and (b)(47) of this section shall apply for those purposes.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

* * * * *

(31) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (b)(38) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (b)(31)(i) through (vi) of this section are presumed to be environmentally beneficial pursuant to paragraph (v)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (v)(2) and (v)(5) of this section.

(i) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(ii) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(iii) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(iv) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(v) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*a*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*b*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*c*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*d*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*e*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(vi) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP), including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (b)(31)(vi)(a) and (b) of this section.

(*a*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*b*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (b)(31)(vi)(b)(1) through (4) of this section.

(*1*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*2*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*3*) Calculate the projected ODP-weighted amount by multiplying the projected annual usage of the new substance by its ODP.

(*4*) If the value calculated in paragraph (b)(31)(vi)(b)(2) of this section is more than the value calculated in paragraph (b)(31)(vi)(b)(3) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(32) [Reserved]

* * * * *

(38) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(39) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

(40)(i) *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.

(ii) In determining the projected actual emissions under paragraph (b)(40)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(*a*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan; and

(*b*) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(*c*) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(47) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

(*d*) In lieu of using the method set out in paragraphs (b)(40)(ii)(*a*) through (*c*) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(41) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved by the Administrator in accordance with paragraph (t) of this section; or any emissions unit that has been designated by a reviewing authority as a Clean Unit, based on the criteria in paragraphs (u)(3)(i) through (iv) of this section, using a plan-approved permitting process; or any emissions unit that has been designated as a Clean Unit by the Administrator in accordance with 52.21 (y)(3)(i) through (iv) of this chapter.

(42) *Prevention of Significant Deterioration Program (PSD) program* means a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of this section, or the program in § 52.21 of this chapter. Any permit issued under such a program is a major NSR permit.

(43) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(44) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O^2 or CO^2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(45) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O^2 or CO^2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(46) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(47) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(47)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*d*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(47)(i)(*b*) of this section.

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority for a permit required either under this section or under a plan approved by the Administrator, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of § 51.165(a)(3)(ii)(G).

(*d*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*e*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(47)(ii)(b) and (c) of this section.

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(47)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(47)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(47)(iii) of this section.

(48) [Reserved]

(49) *Regulated NSR pollutant,* for purposes of this section, means the following:

(i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (*e.g.*, volatile organic compounds are precursors for ozone);

(ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;

(iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

(50) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under § 51.165 and this section, or the Administrator in the case of EPA-implemented permit programs under § 52.21 of this chapter.

(51) *Project* means a physical change in, or change in method of operation of, an existing major stationary source.

(52) *Lowest achievable emission rate (LAER)* is as defined in § 51.165(a)(1)(xiii).

* * * * *

(i) *Exemptions.*

* * * * *

(5) * * *

(i) * * *

(*g*) Fluorides—0.25 $\mu g/m^3$, 24-hour average;

(*h*) Total reduced sulfur—10 $\mu g/m^3$, 1-hour average

(*i*) Hydrogen sulfide—0.2 $\mu g/m^3$, 1-hour average;

(*j*) Reduced sulfur compounds—10 $\mu g/m^3$, 1-hour average; or

* * * * *

(r) * * *

(3) [Reserved]

(4) [Reserved]

(5) [Reserved]

(6) Each plan shall provide that the following specific provisions apply to projects at existing emissions units at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (b)(40)(ii)(*a*) through (*c*) of this section for calculating projected actual emissions. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (r)(6)(i) through (v) of this section.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(*a*) A description of the project;

(*b*) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(*c*) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(40)(ii)(*c*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i) of this section to the reviewing authority. Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the reviewing authority before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(*b*) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section) by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section. Such report shall be submitted to the reviewing authority within 60 days after the end of such year. The report shall contain the following:

(*a*) The name, address and telephone number of the major stationary source;

(*b*) The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

(*c*) Any other information that the owner or operator wishes to include in the report (*e.g.*, an explanation as to why the emissions differ from the preconstruction projection).

(7) Each plan shall provide that the owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon request for inspection by the reviewing authority or the general public pursuant to the requirements contained in § 70.4(b)(3)(viii) of this chapter.

* * * * *

(t) *Clean Unit Test for emissions units that are subject to BACT or LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (t)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (t) apply to any emissions unit for which the reviewing authority has issued a major NSR permit within the past 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (t)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (t)(4) of this section) and before the expiration date (as determined in accordance with paragraph (t)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT and the project would not alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (t)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or the project would alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (t)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (t)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(7)(iv)(*a*) through (*d*) and paragraph (a)(7)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit Applicability Test.* An emissions unit automatically qualifies as a Clean Unit when the unit meets the criteria in paragraphs (t)(3)(i) and (ii) of this section. After the original Clean Unit designation expires in accordance with paragraph (t)(5) of this section or is lost pursuant to paragraph (t)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (t)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (u) of this section. To re-qualify as a Clean Unit under paragraph (t)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable PSD program and meet all the criteria in paragraph (t)(3)(iii) of this section. The Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the past 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(38) of this section or work practices) that meets both the following requirements in paragraphs (t)(3)(ii)(*a*) and (*b*) of this section.

(*a*) The control technology achieves the BACT or LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for the Clean Unit designation if the BACT determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day BACT (or LAER), and the emissions unit must meet the requirements in paragraphs (t)(3)(i) and (t)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (t)(4)(i) or (t)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing a new control technology to meet current-day BACT.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the plan and become effective for the State in which the unit is located.

(ii) *Emissions Units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (t)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day BACT.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (t)(3)(i) and (ii) of this section or re-qualifies by implementing new control technology to meet current-day BACT under paragraph (t)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (t)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (t)(3)(iii) of this section using an existing control technology, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (t)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions related to the Clean Unit in paragraphs (t)(6)(i) through (vi) of this section.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this Clean Unit designation applies.

(ii) The effective date of the Clean Unit designation. If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.*, because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) The expiration date of the Clean Unit designation. If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with BACT, and any physical or operational characteristics that formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (t)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (t)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (t)(7)(i) through (iii) of this section. This paragraph (t)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the BACT that is recorded in the major NSR permit, and subsequently reflected in the title V permit. The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(u) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to BACT.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (u)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (u) apply to emissions units which do not qualify as Clean Units under paragraph (t) of this section, but which are achieving a level of emissions control comparable to BACT, as determined by the reviewing authority in accordance with this paragraph (u).

(2) *General provisions for Clean Units.* The provisions in paragraphs (u)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (u)(5) of this section) and before the expiration date (as determined in accordance with paragraph (u)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (u)(4) of this section) to be comparable to BACT, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (u)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (u)(4) of this section) to be comparable to BACT, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (u)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (u)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(7)(iv)(*a*) through (*d*) and paragraph (a)(7)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (u)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (u)(6) of this section or is lost pursuant to paragraph (u)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (u)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (t) of this section. To re-qualify as a Clean Unit under paragraph (u)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (u)(7) and (8) of this section and meet all the criteria in paragraph (u)(3)(iv) of this section. The reviewing authority will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(38) or work practices) that meets both the following requirements in paragraphs (u)(3)(i)(*a*) and (*b*) of this section.

(*a*) The owner or operator has demonstrated that the emissions unit's control technology is comparable to BACT according to the requirements of paragraph (u)(4) of this section. However, the emissions unit is not eligible for the Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.*, if the BACT determinations to which it is compared have resulted in a determination that no control measures are required).

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The reviewing authority must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before the effective date of plan requirements to implement the requirements of this paragraph (u)(3)(iii). However, for such emissions units, the owner or operator must apply for the Clean Unit designation within 2 years after the plan requirements become effective. For technologies installed after the plan requirements become effective, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (u)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day BACT, and the emissions unit must meet the requirements in paragraphs (u)(3)(i)(*a*) and (u)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to BACT.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to BACT for purposes of paragraph (u)(3)(i) of this section according to either paragraph (u)(4)(i) or (ii) of this section. Paragraph (u)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous BACT and LAER determinations.* The Administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. The reviewing authority shall also compare this presumption to any additional BACT or LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as BACT. In addition, any other person may present evidence related to whether the control technology is substantially as effective as BACT during the public participation process required under paragraph (u)(7) of this section. The reviewing authority shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as BACT.

(iii) *Time of comparison.*

(*a*) *Emissions units with control technologies that are installed before the effective date of plan requirements implementing this paragraph.* The owner or operator of an emissions unit whose control technology is installed before the effective date of plan requirements implementing this paragraph (u) may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (u)(6) of this section.

(*b*) Emissions units with control technologies that are installed after the effective date of plan requirements implementing this paragraph. The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major

modification) is the date that the permit required by paragraph (u)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (u)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (u)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The reviewing authority shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter, including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (u)(8) of this section.

(8) *Required permit content.* The permit required by paragraph (u)(7) of this section shall include the terms and conditions set forth in paragraphs (u)(8)(i) through (vi). Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which the Clean Unit designation applies.

(ii) The effective date of the Clean Unit designation. If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to BACT, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (u)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (u)(9) of this section.

(9) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (u)(9)(i) through (v) of this section. This paragraph (u)(9) applies independently to each pollutant for which the reviewing authority has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to BACT.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) [Reserved]

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis'') unless such use occurs before the effective date of plan requirements adopted to implement this paragraph (u) or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment designation of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (t)(2)(iii) and (u)(2)(iii) of this section, it must re-

qualify under the requirements that are currently applicable.

(v) *PCP exclusion procedural requirements.* Each plan shall include provisions for PCPs equivalent to those contained in paragraphs (v)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the reviewing authority if the project is listed in paragraphs (b)(31)(i) through (vi) of this section, or if the project is not listed in paragraphs (b)(31)(i) through (vi) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the reviewing authority consistent with the requirements in paragraph (v)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (v)(2) of this section, and the notice or permit application must contain the information required in paragraph (v)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements in paragraphs (v)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emission reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (b)(31)(i) through (vi) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the reviewing authority, the owner or operator must include, at a minimum, the information listed in paragraphs (v)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(7)(vi) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (v)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (v)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (v)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant that will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (b)(31)(i) through (vi) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the reviewing authority (unless otherwise prohibited under requirements of the applicable plan). The owner or operator shall respond to any requests by its reviewing authority for additional information that the reviewing authority determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (b)(31)(i) through (vi) of this section, the project must be approved by the reviewing authority and recorded in a plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The reviewing authority must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (v)(6)(i) through (iv) of this section.

(i) *General duty.* The owner or operator must operate the PCP consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (v)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (v)(3), and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (v)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of Emission Reduction Credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation.) The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(w) *Actuals PALs.* The plan shall provide for PALs according to the provisions in paragraphs (w)(1) through (15) of this section.

(1) *Applicability.*

(i) The reviewing authority may approve the use of an actuals PAL for any existing major stationary source if the PAL meets the requirements in paragraphs (w)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (w) of this section.

(ii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (w)(1) through (15) of this section, and complies with the PAL permit:

(*a*) Is not a major modification for the PAL pollutant;

(*b*) Does not have to be approved through the plan's major NSR program; and

(*c*) Is not subject to the provisions in paragraph (r)(2) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program).

(iii) Except as provided under paragraph (w)(1)(ii)(c) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* The plan shall use the definitions in paragraphs (w)(2)(i) through (xi) of this section for the purpose of developing and implementing regulations that authorize the use of actuals PALs consistent with paragraphs (w)(1) through (15) of this section. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (b) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (b)(47) of this section) of all emissions units (as defined in paragraph (b)(7) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (b)(16) of this section, except as this definition is modified according to paragraphs (w)(2)(ii)(*a*) and (*b*) of this section.

(*a*) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(*b*) An emissions unit's potential to emit shall be determined using the definition in paragraph (b)(4) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (b)(23) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(*a*) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(*b*) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (w)(1) through (15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (b)(2) and (b)(3) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the plan, or the title V permit issued by the reviewing authority that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (b)(23) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (w)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information in paragraphs (w)(3)(i) through (iii) of this section to the reviewing authority for approval.

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations, or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown, and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (w)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The plan allows the reviewing authority to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (w)(4)(i)(a) through (g) of this section are met.

(*a*) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(*b*) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (w)(5) of this section.

(*c*) The PAL permit shall contain all the requirements of paragraph (w)(7) of this section.

(*d*) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(*e*) Each PAL shall regulate emissions of only one pollutant.

(*f*) Each PAL shall have a PAL effective period of 10 years.

(*g*) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (w)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant that occur during the PAL effective period creditable as decreases for purposes of offsets under § 51.165(a)(3)(ii) of this chapter unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirements for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased, through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The reviewing authority must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(47) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The plan shall require that the PAL permit contain, at a minimum, the information in paragraphs (w)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (w)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the reviewing authority.

(iv) A requirement that emission calculations for compliance purposes include emissions from startups, shutdowns and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (w)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (w)(3)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (w)(13) of this section.

(viii) A requirement to retain the records required under paragraph (w)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (w)(14) of this section by the required deadlines.

(x) Any other requirements that the reviewing authority deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The plan shall require the information in paragraphs (w)(8)(i) and (ii) of this section.

(i) *PAL effective period.* The reviewing authority shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(*a*) During the PAL effective period, the plan shall require the reviewing authority to reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL;

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under § 51.165(a)(3)(ii) of this chapter; and

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (w)(11) of this section.

(*b*) The plan shall provide the reviewing authority discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date;

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the plan; and

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an AQRV that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(*c*) Except for the permit reopening in paragraph (w)(8)(ii)(*a*)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all reopenings shall be carried out in accordance with the public participation requirements of paragraph (w)(5) of this section.

(9) *Expiration of a PAL.* Any PAL that is not renewed in accordance with the procedures in paragraph (w)(10) of this section shall expire at the end of the PAL effective period, and the

requirements in paragraphs (w)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (w)(9)(i)(*a*) and (*b*) of this section.

(*a*) Within the time frame specified for PAL renewals in paragraph (w)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the reviewing authority) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (w)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(*b*) The reviewing authority shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the reviewing authority determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The reviewing authority may approve the use of monitoring systems (source testing,emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the reviewing authority issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (w)(9)(i)(*b*) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in paragraph (b)(2) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (r)(2) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (w)(1)(ii)(c) of this section.

(10) *Renewal of a PAL.*

(i) The reviewing authority shall follow the procedures specified in paragraph (w)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the reviewing authority.

(ii) *Application deadline.* The plan shall require that a major stationary source owner or operator shall submit a timely application to the reviewing authority to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (w)(10)(iii) (*a*) through (*d*) of this section.

(*a*) The information required in paragraphs (w)(3)(i) through (iii) of this section.

(*b*) A proposed PAL level.

(*c*) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(*d*) Any other information the owner or operator wishes the reviewing authority to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the reviewing authority shall consider the options outlined in paragraphs (w)(10)(iv) (*a*) and (*b*) of this section. However, in no case may any such adjustment fail to comply with paragraph (w)(10)(iv)(*c*) of this section.

(*a*) If the emissions level calculated in accordance with paragraph (w)(6) of this section is equal to or greater than 80 percent of the PAL level, the reviewing authority may renew the PAL at the same level without considering the factors set forth in paragraph (w)(10)(iv)(*b*) of this section; or

(*b*) The reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale.

(*c*) Notwithstanding paragraphs (w)(10)(iv) (*a*) and (*b*) of this section:

(*1*) If the potential to emit of the major stationary source is less than the PAL, the reviewing authority shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The reviewing authority shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (w)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the reviewing authority has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The plan shall require that the reviewing authority may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (w)(11)(i) (*a*) through (*d*) of this section.

(*a*) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(*b*) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s), exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(*c*) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (w)(11)(i)(*a*) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT), even though they have also become subject to the PAL or continue to be subject to the PAL.

(*d*) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The reviewing authority shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (w)(11)(i)(*b*) of this section), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (w)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) *General requirements.*

(*a*) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(*b*) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (w)(12)(ii) (*a*) through (*d*) of this section and must be approved by the reviewing authority.

(*c*) Notwithstanding paragraph (w)(12)(i)(*b*) of this section, you may also employ an alternative monitoring approach that meets paragraph (w)(12)(i)(*a*) of this section if approved by the reviewing authority.

(*d*) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum performance requirements for approved monitoring approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (w)(12)(iii) through (ix) of this section:

(*a*) Mass balance calculations for activities using coatings or solvents;

(*b*) CEMS;

(*c*) CPMS or PEMS; and

(*d*) Emission factors.

(iii) Mass balance calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(*a*) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(*b*) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(*c*) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the reviewing authority determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(*b*) CEMS must sample, analyze, and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(*b*) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the reviewing authority, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(*b*) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(*c*) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (w)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the reviewing authority shall, at the time of permit issuance:

(*a*) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(*b*) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the reviewing authority. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (w) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records, for the duration of the PAL effective period plus 5 years:

(*a*) A copy of the PAL permit application and any applications for revisions to the PAL; and

(*b*) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the reviewing authority in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (w)(14)(i) through (iii) of this section.

(i) *Semi-annual report.* The semi-annual report shall be submitted to the reviewing authority within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (w)(14)(i)(*a*) through (*g*) of this section.

(*a*) The identification of owner and operator and the permit number.

(*b*) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (w)(13)(i) of this section.

(*c*) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(*d*) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(*e*) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(*f*) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by paragraph (w)(12)(vii) of this section.

(*g*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) *Deviation report.* The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(*a*) The identification of owner and operator and the permit number;

(*b*) The PAL requirement that experienced the deviation or that was exceeded;

(*c*) Emissions resulting from the deviation or the exceedance; and

(*d*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) Re-validation results. The owner or operator shall submit to the reviewing authority the results of any re-validation test or method within three months after completion of such test or method.

(15) *Transition requirements.*

(i) No reviewing authority may issue a PAL that does not comply with the requirements in paragraphs (w)(1) through (15) of this section after the Administrator has approved regulations incorporating these requirements into a plan.

(ii) The reviewing authority may supersede any PAL which was established prior to the date of approval of the plan by the Administrator with a PAL that complies with the requirements of paragraphs (w)(1) through (15) of this section.

(x) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

PART 52—[AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

2. In 40 CFR 52.21(b)(1)(i)(*b*) and (b)(5), remove the words ''any air pollutant subject to regulation under the Act,'' and add, in their place, the words ''a regulated NSR pollutant.''

3. In addition to the amendments set forth above, section 52.21 is amended:

a. By redesignating paragraph (a) as paragraph (a)(1).

b. By adding paragraph (a)(2).

c. By revising paragraphs (b)(2)(i) and (ii).

d. By revising paragraph (b)(2)(iii)(*h*).

e. By adding paragraph (b)(2)(iv).

f. By revising paragraph (b)(3)(i).

g. By revising paragraphs (b)(3)(iii) and (iv).

h. By revising paragraphs (b)(3)(vi)(*b*) and (*c*).

i. By adding paragraph (b)(3)(vi)(*d*).

j. By adding paragraph (b)(3)(ix).

k. By revising paragraphs (b)(7) and (8).

l. By revising paragraph (b)(13).

m. By revising paragraph (b)(21).

n. By removing the following items from the list in paragraph (b)(23)(i): ''Asbestos: 0.007 tpy''; ''Beryllium: 0.0004 tpy''; ''Mercury: 0.1 tpy''; and ''Vinyl Chloride: 1 tpy''.

o. By revising paragraph (b)(32).

p. By removing and reserving paragraph (b)(33).

q. By adding paragraphs (b)(39) through (48), adding and reserving paragraph (b)(49), and by adding paragraphs (b)(50) through (b)(54).

r. By revising the introductory text of paragraph (i).

s. By removing paragraphs (i)(1) through (3).

t. By redesignating paragraphs (i)(4) through (13) as paragraphs (i)(1) through (10).

u. By removing the following items from the list in newly redesignated paragraph (i)(5)(i): ''Mercury—0.25 $\mu g/m^3$, 24-hour average''; ''Beryllium—0.001 $\mu g/m^3$, 24-hour average''; ''Vinyl chloride—15 $\mu g/m^3$, 24-hour average''.

v. By adding and reserving paragraphs (r)(5) and adding paragraphs (r)(6) through (7).

w. By adding paragraphs (x) through (bb).

4. In addition to the amendments set forth above, in 40 CFR 52.21, remove the words ''pollutant subject to regulation under the Act'' and add, in their place, the words ''regulated NSR pollutant'' in the following places:

a. (b)(1)(i)(*a*);
b. (b)(2)(i);
c. (b)(23)(ii);
d. newly redesignated (i)(4); and
e. (j)(2) and (3).

The revisions and additions read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(a)(1) *Plan disapproval.* * * *

(2) *Applicability procedures.* (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

(iii) No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements. The Administrator has authority to issue any such permit.

(iv) The requirements of the program will be applied in accordance with the principles set out in paragraphs (a)(2)(iv)(*a*) through (*f*) of this section.

(*a*) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (b)(40) of this section), and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(*b*) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(*c*) through (*f*) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(*c*) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*e*) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(*c*) through (*e*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(iv)(*c*) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(*e*) of this section for the Clean Unit.

(v) For any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with the requirements under paragraph (aa) of this section.

(vi) An owner or operator undertaking a PCP (as defined in paragraph (b)(32) of this section) shall comply with the requirements under paragraph (z) of this section.

* * * * *

(b) * * *

(2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(ii) Any significant emissions increase (as defined in paragraph (b)(40) of this section) from any emissions units or net emissions increase (as defined in paragraph (b)(3) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) * * *

(*h*) The addition, replacement, or use of a PCP, as defined in paragraph (b)(32) of this section, at an existing emissions unit meeting the requirements of paragraph (z) of this section. A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(iv) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (aa) of this section for a PAL for that pollutant. Instead, the definition at paragraph (aa)(2)(viii) of this section shall apply.

(3)(i) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*a*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and

(*b*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.

Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(*b*) shall be determined as provided in paragraph (b)(48) of this section, except that paragraphs (b)(48)(i)(*c*) and (b)(48)(ii)(*d*) of this section shall not apply.

* * * * *

(iii) An increase or decrease in actual emissions is creditable only if:

(*a*) The Administrator or other reviewing authority has not relied on it in issuing a permit for the source under this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*b*) The increase or decrease in emissions did not occur at a Clean Unit except as provided in paragraphs (x)(8) and (y)(10) of this section.

(iv) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

* * * * *

(vi) * * *

(*b*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins.

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*d*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under paragraph (y) of this section or under regulations approved pursuant to § 51.165(d) or to § 51.166(u) of this chapter. That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emission reductions that were not relied upon in a PCP excluded pursuant to paragraph (z) of this section or for a Clean Unit designation are creditable to the extent they meet the requirements in paragraph (z)(6)(iv) of this section for the PCP and paragraphs (x)(8) or (y)(10) of this section for a Clean Unit.

* * * * *

(ix) Paragraph (b)(21)(ii) of this section shall not apply for determining creditable increases and decreases.

(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section.

(8) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(13)(i) *Baseline concentration* means that ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(*a*) The actual emissions, as defined in paragraph (b)(21) of this section, representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph (b)(13)(ii) of this section; and

(*b*) The allowable emissions of major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date; and

(*b*) Actual emissions increases and decreases, as defined in paragraph (b)(21) of this section, at any stationary source occurring after the minor source baseline date.

* * * * *

(21)(i) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii) through (iv) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (aa) of this section. Instead, paragraphs (b)(41) and (b)(48) of this section shall apply for those purposes.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

* * * * *

(32) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (b)(39) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (b)(32)(i) through (vi) of this section are presumed to be environmentally beneficial pursuant to paragraph (z)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (z)(2) and (z)(5) of this section.

(i) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(ii) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(iii) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(iv) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(v) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*a*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*b*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*c*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*d*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*e*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(vi) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP,) including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (b)(32)(vi)(*a*) and (*b*) of this section.

(*a*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*b*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (b)(32)(vi)(*b*)(*1*) through (*4*) of this section.

(*1*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*2*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*3*) Calculate the projected ODP-weighted amount by multiplying the projected actual usage of the new substance by its ODP.

(*4*) If the value calculated in paragraph (b)(32)(vi)(*b*)(*2*) of this section is more than the value calculated in paragraph (b)(32)(vi)(*b*)(*3*) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(33) [Reserved]

* * * * *

(39) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(40) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

(41)(i) *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(*a*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and

(*b*) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(*c*) Shall exclude, in calculating any increase in emissions that results from he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or

(*d*) In lieu of using the method set out in paragraphs (a)(41)(ii)(a) through (c) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(42) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to paragraph (x) of this section; or any emissions unit that has been designated by the Administrator as a Clean Unit, based on the criteria in paragraphs (y)(3)(i) through (iv) of this section; or any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved into the State Implementation Plan in accordance with § 51.165(c) or § 51.166(u) of this chapter; or any emissions unit that has been designated by the reviewing authority as a Clean Unit in accordance with regulations approved into the plan to carry out § 51.165(d) or § 51.166(u) of this chapter.

(43) *Prevention of Significant Deterioration (PSD) program* means the EPA-implemented major source preconstruction permit programs under this section or a major source preconstruction permit program that has been approved by the Administrator and incorporated into the State Implementation Plan pursuant to § 51.166 of this chapter to implement the requirements of that section. Any permit issued under such a program is a major NSR permit.

(44) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(45) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(46) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(47) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(48) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*d*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(48)(i)(*b*) of this section.

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of § 51.165(a)(3)(ii)(G) of this chapter.

(*d*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*e*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(48)(ii)(*b*) and (*c*) of this section.

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(48)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(48)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(48)(iii) of this section.

(49) [Reserved]

(50) *Regulated NSR pollutant,* for purposes of this section, means the following:

(i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (*e.g.*, volatile organic compounds are precursors for ozone);

(ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;

(iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

(51) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under § 51.165 and § 51.166 of this chapter, or the Administrator in the case of EPA-implemented permit programs under this section.

(52) *Project* means a physical change in, or change in the method of operation of, an existing major stationary source.

(53) *Lowest achievable emission rate (LAER)* is as defined in § 51.165(a)(1)(xiii) of this chapter.

(54) *Reasonably available control technology (RACT)* is as defined in § 51.100(o) of this chapter.

* * * * *

(i) Exemptions. * * *

* * * * *

(r) * * *

(5) [Reserved]

(6) The provisions of this paragraph (r)(6) apply to projects at an existing emissions unit at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(*a*) through (*c*) of this section for calculating projected actual emissions.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(*a*) A description of the project;

(*b*) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(*c*) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(41)(ii)(*c*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i) of this section to the Administrator. Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(*b*) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Administrator within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Administrator if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section), by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section. Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

(*a*) The name, address and telephone number of the major stationary source;

(*b*) The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

(*c*) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

(7) The owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon a request for inspection by the Administrator or the general public pursuant to the requirements contained in § 70.4(b)(3)(viii) of this chapter.

* * * * *

(x) *Clean Unit Test for emissions units that are subject to BACT or LAER.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (x)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (x) apply to any emissions unit for which a reviewing authority has issued a major NSR permit within the last 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (x)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (x)(4) of this section) and before the expiration date (as determined in accordance with paragraph (x)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT and the project would not alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or the project would alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (x)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit Applicability Test.* An emissions unit automatically qualifies

as a Clean Unit when the unit meets the criteria in paragraphs (x)(3)(i) and (ii) of this section. After the original Clean Unit expires in accordance with paragraph (x)(5) of this section or is lost pursuant to paragraph (x)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (x)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (y) of this section. To re-qualify as a Clean Unit under paragraph (x)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable PSD program and meet all the criteria in paragraph (x)(3)(iii) of this section. The Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the last 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (x)(3)(ii)(*a*) and (*b*) of this section.

(*a*) The control technology achieves the BACT or LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for the Clean Unit designation if the BACT determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day BACT (or LAER), and the emissions unit must meet the requirements in paragraphs (x)(3)(i) and (x)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (x)(4)(i) or (x)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing new control technology to meet current-day BACT.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than March 3, 2003, that is the date these provisions become effective.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (x)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day BACT.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (x)(3)(i) and (ii) of this section or re-qualifies by implementing new control technology to meet current-day BACT under paragraph (x)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (x)(3)(iii) of this section using an existing control technology, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions in paragraphs (x)(6)(i) through (vi) of this section related to the Clean Unit.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.,* because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.,* the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.,* because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.,* the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with BACT, and any physical or operational characteristics which formed the basis for the BACT determination (*e.g.,* possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (x)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (x)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit

designation, the owner or operator must conform to all the restrictions listed in paragraphs (x)(7)(i) through (iii) of this section. This paragraph (x)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the BACT that is recorded in the major NSR permit, and subsequently reflected in the title V permit. The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the BACT determination (*e.g.,* possibly the emissions unit's capacity or throughput).

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by re-designation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(y) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to BACT.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (y)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (y) apply to emissions units which do not qualify as Clean Units under paragraph (x) of this section, but which are achieving a level of emissions control comparable to BACT, as determined by the Administrator in accordance with this paragraph (y).

(2) *General provisions for Clean Units.* The provisions in paragraphs (y)(2)(i) through (iv) of this section apply to a Clean Unit (designated under this paragraph (y)).

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (y)(5) of this section) and before the expiration date (as determined in accordance with paragraph (y)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (u)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (y)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (y)(6) of this section or is lost pursuant to paragraph (y)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (y)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (x) of this section. To re-qualify as a Clean Unit under paragraph (y)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (y)(7) and (8) of this section and meet all the criteria in paragraph (y)(3)(iv) of this section. The Administrator will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (y)(3)(i)(*a*) and (*b*) of this section.

(*a*) The owner or operator has demonstrated that the emissions unit's control technology is comparable to BACT according to the requirements of paragraph (y)(4) of this section. However, the emissions unit is not eligible for a Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.,* if the BACT determinations to which it is compared have resulted in a determination that no control measures are required).

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The Administrator must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before March 3, 2003. However, for such emissions units, the owner or operator must apply for the Clean Unit designation before December 31, 2004. For technologies installed on and after March 3, 2003, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (y)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day BACT, and the emissions unit must meet the requirements in paragraphs (y)(3)(i)(a) and (y)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to BACT.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to BACT for purposes of paragraph (y)(3)(i) of this section according to either paragraph (y)(4)(i) or (ii) of this section. Paragraph (y)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous BACT and LAER determinations.* The Administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. The Administrator shall also compare this presumption to any additional BACT or LAER determinations of which he or she is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as BACT. In addition, any other person may present evidence related to whether the control technology is substantially as effective as BACT during the public participation process required under paragraph (y)(7) of this section. The Administrator shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as BACT.

(iii) *Time of comparison.*

(*a*) *Emissions units with control technologies that are installed before March 3, 2003.* The owner or operator of an emissions unit whose control technology is installed before March 3, 2003 may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (y)(6) of this section.

(*b*) *Emissions units with control technologies that are installed on and after March 3, 2003.* The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major modification) is the date that the permit required by paragraph (y)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (y)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (y)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The Administrator shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (y)(8) of this section.

(8) *Required permit content.* The permit required by paragraph (y)(7) of this section shall include the terms and conditions set forth in paragraphs (y)(8)(i) through (vi) of this section. Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) The expiration date of the Clean Unit designation. If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to BACT, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (y)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (y)(9) of this section.

(9) *Maintaining a Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (y)(9)(i) through (v) of this section. This paragraph (y)(9) applies independently to each pollutant for which the Administrator has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to BACT.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) [Reserved]

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a "netting analysis") unless such use occurs before March 3, 2003 or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on a Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (x)(2)(iii) and (y)(2)(iii) of this section, it must re-qualify under the requirements that are currently applicable.

(z) *PCP exclusion procedural requirements.* PCPs shall be provided according to the provisions in paragraphs (z)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the Administrator if the project is listed in paragraphs (b)(32)(i) through (vi) of this section, or if the project is not listed in paragraphs (b)(32)(i) through (vi) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the Administrator consistent with the requirements in paragraph (z)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (z)(2) of this section, and the notice or permit application must contain the information required in paragraph (z)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements of paragraphs (z)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emissions reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (b)(32)(i) through (vi) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the Administrator, the owner or operator must include, at a minimum, the information listed in paragraphs (z)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(2)(iv) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (z)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71 of this chapter.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (z)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant that will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (b)(32)(i) through (vi) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the Administrator (unless otherwise prohibited under requirements of the applicable State Implementation Plan). The owner or operator shall respond to any requests by the Administrator for additional information that the Administrator determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (b)(32)(i) through (vi) of this section, the project must be approved by the Administrator and recorded in a State Implementation Plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The Administrator must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (z)(6)(i) through (iv) of this section.

(i) *General duty.* The owner or operator must operate the PCP in a manner consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (z)(3) of this section, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (z)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the State Implementation Plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of emission reduction credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation). The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(aa) *Actuals PALs.* The provisions in paragraphs (aa)(1) through (15) of this section govern actuals PALs.

(1) *Applicability.*

(i) The Administrator may approve the use of an actuals PAL for any existing major stationary source if the PAL meets the requirements in paragraphs (aa)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (aa) of this section.

(ii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (aa)(1) through (15) of this section, and complies with the PAL permit:

(*a*) Is not a major modification for the PAL pollutant;

(*b*) Does not have to be approved through the PSD program; and

(*c*) Is not subject to the provisions in paragraph (r)(4) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program).

(iii) Except as provided under paragraph (aa)(1)(ii)(*c*) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* For the purposes of this section, the definitions in paragraphs (aa)(2)(i) through (xi) of this section apply. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (b) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (b)(48) of this section) of all emissions units (as defined in paragraph (b)(7) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (b)(16) of this section, except as this definition is modified according to paragraphs (aa)(2)(ii)(*a*) and (*b*) of this section.

(*a*) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(*b*) An emissions unit's potential to emit shall be determined using the definition in paragraph (b)(4) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (b)(23) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(*a*) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(*b*) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (aa)(1) through (15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (b)(2) and (b)(3) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the State Implementation Plan, or the title V permit issued by the Administrator that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (b)(23) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (aa)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information to the Administrator for approval:

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations, or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown, and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (aa)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The Administrator is allowed to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (aa)(4)(i)(a) through (g) of this section are met.

(*a*) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(*b*) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (aa)(5) of this section.

(*c*) The PAL permit shall contain all the requirements of paragraph (aa)(7) of this section.

(*d*) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(*e*) Each PAL shall regulate emissions of only one pollutant.

(*f*) Each PAL shall have a PAL effective period of 10 years.

(*g*) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (aa)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant that occur during the PAL effective period creditable as decreases for purposes of offsets under § 51.165(a)(3)(ii) of this chapter unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirements for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The Administrator must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(48) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The Administrator shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future

compliance date(s) of any applicable Federal or State regulatory requirement(s) that the Administrator is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The PAL permit must contain, at a minimum, the information in paragraphs (aa)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (aa)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by a reviewing authority.

(iv) A requirement that emission calculations for compliance purposes must include emissions from startups, shutdowns, and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (aa)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total as required by paragraph (aa)(13)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (aa)(12) of this section.

(viii) A requirement to retain the records required under paragraph (aa)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (aa)(14) of this section by the required deadlines.

(x) Any other requirements that the Administrator deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The requirements in paragraphs (aa)(8)(i) and (ii) of this section apply to actuals PALs.

(i) *PAL effective period.* The Administrator shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(*a*) During the PAL effective period, the Administrator must reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL;

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under § 51.165(a)(3)(ii) of this chapter; and

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (aa)(11) of this section.

(*b*) The Administrator shall have discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date;

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the State Implementation Plan; and

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(*c*) Except for the permit reopening in paragraph (aa)(8)(ii)(*a*)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of paragraph (aa)(5) of this section.

(9) *Expiration of a PAL.* Any PAL that is not renewed in accordance with the procedures in paragraph (aa)(10) of this section shall expire at the end of the PAL effective period, and the requirements in paragraphs (aa)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (aa)(9)(i)(*a*) and (*b*) of this section.

(*a*) Within the time frame specified for PAL renewals in paragraph (aa)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the Administrator) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (aa)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(*b*) The Administrator shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Administrator determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The Administrator may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS, or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the Administrator issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (aa)(9)(i)(*b*) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in paragraph (b)(2) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (r)(4) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (aa)(1)(ii)(*c*) of this section.

(10) *Renewal of a PAL.*

(i) The Administrator shall follow the procedures specified in paragraph (aa)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the Administrator.

(ii) *Application deadline.* A major stationary source owner or operator shall submit a timely application to the Administrator to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (aa)(10)(iii)(*a*) through (*d*) of this section.

(*a*) The information required in paragraphs (aa)(3)(i) through (iii) of this section.

(*b*) A proposed PAL level.

(*c*) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(*d*) Any other information the owner or operator wishes the Administrator to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the Administrator shall consider the options outlined in paragraphs (aa)(10)(iv)(*a*) and (*b*) of this section. However, in no case may any such adjustment fail to comply with paragraph (aa)(10)(iv)(*c*) of this section.

(*a*) If the emissions level calculated in accordance with paragraph (aa)(6) of this section is equal to or greater than 80 percent of the PAL level, the Administrator may renew the PAL at the same level without considering the factors set forth in paragraph (aa)(10)(iv)(*b*) of this section; or

(*b*) The Administrator may set the PAL at a level that he or she determines to be more representative of the source's baseline actual emissions, or that he or she determines to be more appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the Administrator in his or her written rationale.

(*c*) Notwithstanding paragraphs (aa)(10)(iv)(a) and (b) of this section:

(*1*) If the potential to emit of the major stationary source is less than the PAL, the Administrator shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The Administrator shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (aa)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the Administrator has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The Administrator may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (aa)(11)(i)(*a*) through (*d*) of this section.

(*a*) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(*b*) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(*c*) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (aa)(11)(i)(*a*) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT), even though they have also become subject to the PAL or continue to be subject to the PAL.

(*d*) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The Administrator shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (aa)(11)(i)(*b*)), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (aa)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) General requirements.

(*a*) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(*b*) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (aa)(12)(ii)(*a*) through (*d*) of this section and must be approved by the Administrator.

(*c*) Notwithstanding paragraph (aa)(12)(i)(*b*) of this section, you may also employ an alternative monitoring approach that meets paragraph (aa)(12)(i)(*a*) of this section if approved by the Administrator.

(*d*) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum performance requirements for approved monitoring approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (aa)(12)(iii) through (ix) of this section:

(*a*) Mass balance calculations for activities using coatings or solvents;

(*b*) CEMS;

(*c*) CPMS or PEMS; and

(*d*) Emission factors.

(iii) Mass balance calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(*a*) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(*b*) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(*c*) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the Administrator determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(*b*) CEMS must sample, analyze and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(*b*) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the Administrator, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(*b*) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(*c*) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the Administrator determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (aa)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the Administrator shall, at the time of permit issuance:

(*a*) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(*b*) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the Administrator. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (aa) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus 5 years:

(*a*) A copy of the PAL permit application and any applications for revisions to the PAL; and

(*b*) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the Administrator in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (aa)(14)(i) through (iii) of this section.

(i) *Semi-annual report.* The semi-annual report shall be submitted to the Administrator within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (aa)(14)(i)(*a*) through (*g*) of this section.

(*a*) The identification of owner and operator and the permit number.

(*b*) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (aa)(13)(i) of this section.

(*c*) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(*d*) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(*e*) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(*f*) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by (aa)(12)(vii).

(*g*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) *Deviation report.* The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(*a*) The identification of owner and operator and the permit number;

(*b*) The PAL requirement that experienced the deviation or that was exceeded;

(*c*) Emissions resulting from the deviation or the exceedance; and

(*d*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) *Re-validation results.* The owner or operator shall submit to the Administrator the results of any re-validation test or method within 3 months after completion of such test or method.

(15) *Transition requirements.*

(i) The Administrator may not issue a PAL that does not comply with the requirements in paragraphs (aa)(1) through (15) of this section after March 3, 2003.

(ii) The Administrator may supersede any PAL that was established prior to March 3, 2003 with a PAL that complies with the requirements of paragraphs (aa)(1) through (15) of this section.

(bb) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

[FR Doc. 02–31899 Filed 12–30–02; 8:45 am]

BILLING CODE 6560–50–P

HUNTON & WILLIAMS

HUNTON & WILLIAMS LLP
2200 PENNSYLVANIA AVENUE, NW
WASHINGTON, D.C. 20037-1701

TEL 202 • 955 • 1500
FAX 202 • 778 • 2201

ANDREA FIELD
DIRECT DIAL: 202 • 955 • 1558
EMAIL: afield@hunton.com

May 12, 2017

Samantha K. Dravis
Regulatory Reform Officer and
Associate Administrator, Office of Policy
U.S. Environmental Protection Agency
Mail Code 1803A
1200 Pennsylvania Avenue NW
Washington, D.C. 20460

Submitted via Electronic Mail and via Regulations.gov

Utility Air Regulatory Group's Response to EPA's Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 Fed. Reg. 17,793 (Apr. 13, 2017): Docket ID No. EPA-HQ-OA-2017-0190

Dear Ms. Dravis:

This letter is submitted in response to the U.S. Environmental Protection Agency's ("EPA" or "Agency") April 13, 2017 *Federal Register* notice[1] seeking input from the public to inform the Agency's evaluation of existing regulations that may meet the criteria outlined in Executive Order 13777[2] for repeal, replacement, or modification. More specifically, the notice asks commenters to identify regulations that, among other things, "are outdated, unnecessary, or ineffective; impose costs that exceed benefits; . . . or . . . derive from or implement Executive Orders or other Presidential directives that have been subsequently rescinded or substantially modified,"[3] in accordance with the language of Executive Order 13777.

The Utility Air Regulatory Group ("UARG") recommends that EPA examine whether the regulations identified below meet the criteria of Executive Order 13777. UARG is a not-for-profit association of individual electric generating companies and national trade associations. Since 1977, UARG has participated on behalf of certain of its members collectively in scores of Clean Air Act ("CAA" or "Act") administrative proceedings that affect electric generators and in litigation arising from those proceedings. UARG's 40 years of participation in CAA rulemakings and litigation has provided it unique insight as to which CAA programs are

[1] 82 Fed. Reg. 17,793 (Apr. 13, 2017).
[2] 82 Fed. Reg. 12,285 (Mar. 1, 2017).
[3] 82 Fed. Reg. at 17,793.

designed and work as Congress intended, which programs are overly burdensome or costly, and which programs are unlawful or unnecessary.

Many of the recommendations set out below are described in greater detail in materials that UARG has previously filed with EPA and reviewing courts. These materials include rulemaking comments, technical expert reports, petitions for reconsideration, and court pleadings concerning Agency actions that UARG believes to be unlawful, unjustified, or unduly burdensome or costly. UARG appreciates the opportunity to provide input on this matter and invites Agency representatives and others in the administration to meet with UARG concerning the information that we are providing today.[4]

[4] Dominion Energy does not join in these comments.

TABLE OF CONTENTS

I. Climate Change-Related Rules ... **5**

A. Clean Power Plan, 80 Fed. Reg. 64,662 (Oct. 23, 2015), codified at 40 C.F.R. Part 60, Subpart UUUU ... 5

B. Carbon Dioxide New Source Performance Standards for New, Modified, and Reconstructed Electric Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015), codified at 40 C.F.R. Part 60, Subpart TTTT ... 5

C. Greenhouse Gas Mandatory Reporting Rule ("GHG MRR"), codified at 40 C.F.R. Part 98 6

II. Cross-State Air Pollution Rule ("CSAPR") Update Rule ... **8**

III. Regional Haze and Other Visibility Regulations ... **10**

IV. Regulation of Hazardous Air Pollutants ... **12**

A. Compliance Provisions of the Mercury and Air Toxics Standards ("MATS") Rule, codified at 40 C.F.R. Part 63, Subpart UUUUU ... 12

B. Renewed Analysis of Potentially Delisting Natural Gas-Fired Stationary Combustion Turbines from Regulation Under CAA Section 112 ... 14

C. National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards for Stationary Reciprocating Internal Combustion Engines ("RICE"), codified at 40 C.F.R. Part 60 Subparts IIII and JJJJ and 40 C.F.R. Part 63 Subpart ZZZZ ... 15

V. Preconstruction Permitting Issues ... **16**

A. New Source Review ("NSR") Reform ... 16

B. Synthetic Minor Sources ... 17

C. Prevention of Significant Deterioration ("PSD") Significant Emissions Rate for Greenhouse Gases ... 18

VI. New Source Performance Standards ("NSPS") Issues ... **19**

A. Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills, 81 Fed. Reg. 59,276 (Aug. 29, 2016), codified at 40 C.F.R. Part 60, Subpart Cf ... 19

B. Electronic Reporting Under the NSPS, codified at 40 C.F.R. Part 60 ... 20

C. Reconsideration of the NSPS for Stationary Combustion Turbines, codified at 40 C.F.R. Part 60, Subpart KKKK ... 22

D. Reconsideration of the NSPS for Coal Preparation and Processing Plants, codified at 40 C.F.R. Part 60, Subpart Y ... 23

E. Revisions to Test Method for Determining Stack Test Gas Velocity Taking Into Account Velocity Decay Near the Stack Walls 23

VII. National Ambient Air Quality Standards 24

A. "Findings of Substantial Inadequacy" of SIPs and "SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction," published at 80 Fed. Reg. 33,840 (June 12, 2015) 24

B. NAAQS Promulgation and Implementation 25

VIII. Air Quality Modeling Issues 27

IX. Demonstration-of-Compliance Issues 28

A. Outreach on Current Rulemakings 28

B. The So-Called "Credible Evidence Rule" 29

I. Climate Change-Related Rules

A. Clean Power Plan, 80 Fed. Reg. 64,662 (Oct. 23, 2015), codified at 40 C.F.R. Part 60, Subpart UUUU

EPA has already commenced review of this rule to determine whether it is appropriate to "initiate proceedings to suspend, revise or rescind the Clean Power Plan."[5] Any replacement or revision to the Clean Power Plan under CAA § 111(d) must adhere to the statutory confines of section 111 of the CAA and must: (i) be based on a "best system of emission reduction" that can be applied at the individual electric generating units subject to the rule; (ii) adhere to the requirement of section 111(d) of the CAA and its implementing regulations that states (and EPA when it is acting on behalf of a state) be allowed to prescribe less stringent standards for certain units on an as-needed, case-by-case basis; and (iii) adhere to the requirement of section 111(d) of the CAA that the remaining useful life of the unit be taken into account. Any replacement rule should also allow for compliance flexibility. Likewise, UARG encourages EPA to acknowledge that once it has promulgated emission guidelines for a source category, the CAA does not give the Agency authority to revisit those guidelines and make them more stringent. *See* Section VI.A below.

B. Carbon Dioxide New Source Performance Standards for New, Modified, and Reconstructed Electric Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015), codified at 40 C.F.R. Part 60, Subpart TTTT

EPA has already commenced review of this rule to determine whether it is appropriate to "initiate proceedings to suspend, revise or rescind the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units."[6] As part of its comments on EPA's proposed performance standards and its petition for reconsideration of the final standards, UARG engaged experts to prepare numerous technical reports explaining to EPA why the performance standards EPA proposed (and later finalized) were neither based on adequately demonstrated systems of emission reduction nor achievable; these technical reports are available in the rulemaking docket.[7]

---

[5] 82 Fed. Reg. 16,329 (Apr. 4, 2017).

[6] 82 Fed. Reg. 16,330 (Apr. 4, 2017).

[7] *See* UARG Comments on Proposed GHG NSPS for New Electric Generating Units ("EGUs") at Attachments 1-3, 5, 9, 11 (May 9, 2014), EPA-HQ-OAR-2013-0495-9666; UARG Comments on Proposed GHG NSPS for Modified and Reconstructed EGUs at Attachments B, C, G, K (Oct. 16, 2014), EPA-HQ-OAR-2013-0603-0215; UARG Petition for Reconsideration of Final GHG NSPS at Exhibit J (Dec. 22, 2015), EPA-HQ-OAR-2013-0495-11894.

Any replacement or revision to the greenhouse gas ("GHG") standards of performance for new, modified, and reconstructed electric generating units must adhere to the statutory confines of section 111 of the CAA, must be based on a "best system of emission reduction" that has been adequately demonstrated, and must be achievable by the individual electric generating units subject to the rule.

Of particular note, any replacement or revision to these standards of performance cannot, for the purposes of determining the "best system of emission reduction," take into account technology that received funding or tax subsidies under the Energy Policy Act of 2005, as consideration of those technologies for that purpose is prohibited by that Act.

C. Greenhouse Gas Mandatory Reporting Rule ("GHG MRR"), codified at 40 C.F.R. Part 98

Under the fiscal year 2008 Consolidated Appropriations Act, Congress authorized funding for EPA to develop and publish a rule "to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States."[8] The joint explanatory statement accompanying the legislation directed EPA to use its existing authority under the CAA (e.g., authority under CAA § 114) to develop a mandatory GHG reporting rule covering those upstream production and downstream sources the Administrator deems "appropriate," and to determine "appropriate thresholds" and frequency for reporting.[9] Congress also authorized EPA to rely on the "existing reporting requirements for electric generating units under section 821 of the 1990 CAA Amendments."[10]

The reporting program has resulted in facilities expending enormous resources tracking, quality assuring, and reporting vast amounts of information. EPA also continues to spend significant resources for both its own staff and Agency contractors to implement the GHG MRR and its electronic reporting requirements. Since its initial promulgation in October 2009, EPA has revised the regulation dozens of times. Although UARG understands that many of these rule revisions have been directed at correcting errors or simplifying data collection and reporting, the need for so many revisions underscores the complicated nature of the program.

In the past, UARG has questioned the "practical utility"[11] of much of the collected information and offered suggestions for simplification of the program. For example, under

[8] Pub. L. No. 110–161, 121 Stat. 1844, 2128 (2007).

[9] 74 Fed. Reg. 16,448, 16,454 (Apr. 10, 2009).

[10] *Id.* (internal quotation marks omitted).

[11] EPA's authority to collect information under CAA § 114 is limited by the Paperwork Reduction Act and its implementing regulations. To require a data collection, EPA must

Subpart C, which covers general "stationary fuel combustion sources," the term is defined simply as a device that combusts fuel and does not require that the device be used for any particular purpose.[12] As a result, facilities with total emissions above the rule's applicability threshold must include in their facility-wide calculation miscellaneous combustion devices, like small gas-fired heaters, stoves, lawn mowers, or even hot water heaters. Reporting GHG emissions from such miscellaneous devices is time consuming and the information is of little value. UARG previously asked EPA either to define more narrowly what type of device triggers reporting or to adopt a *de minimis* threshold for reporting emissions from such devices at a stationary fuel combustion source.[13]

Now that the program has been in place for more than seven years, and EPA has provided Congress the information it sought, EPA should review how all of the information being collected has been used and whether the Agency's assumptions about the information's "practical utility" are correct. EPA should use this information to tailor the program so that it provides a significant "net benefit" consistent with the objectives of Executive Order 13777. At a minimum, UARG encourages EPA to establish a *de minimis* cut-off for reporting emissions from miscellaneous activities and streamline by "auto-populating" any emissions already being reported under another federal regulatory program, such as CO_2 emissions data collected under 40 C.F.R. Part 75.

In addition, as part of the rulemakings discussed in Sections I.A and I.B above, EPA amended Part 98 to impose additional reporting requirements on owners of electric generating units that transfer captured carbon dioxide to sites reporting under Subpart RR, while also requiring units to transfer their captured carbon dioxide to Subpart RR reporting sites if they wish to rely on carbon capture to meet an applicable emission limit or earn emission reduction credits. EPA should reconsider this requirement, which is unduly burdensome, costly, and does not have any environmental benefit.

---

demonstrate the "practical utility" of the covered information. 5 C.F.R. § 1320.5(d)(1)(iii). Under 5 C.F.R. § 1320.3(l),

> *Practical utility* means the actual, *not merely the theoretical or potential,* usefulness of information…. In determining whether information will have 'practical utility,' OMB will take into account whether the agency demonstrates *actual timely use* for the information….

(emphases added).

[12] 40 C.F.R § 98.30(a).

[13] *See, e.g.*, UARG Comments on Proposed GHG MRR (June 9, 2009), EPA-HQ-OAR-2008-0508-0493.

II. Cross-State Air Pollution Rule ("CSAPR") Update Rule

EPA should reconsider and modify certain aspects of the Cross-State Air Pollution Rule Update for the 2008 Ozone National Ambient Air Quality Standards ("NAAQS") (known as the "CSAPR Update Rule").[14] The CSAPR Update Rule establishes stringent "ozone-season" (May-through-September) budgets for additional limits on emissions of nitrogen oxides ("NOx") from fossil fuel-fired electric generating units, beginning this month, in each of 22 states: Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas. Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. The rule is a new regulatory program that imposes costs exceeding any reasonable measure of projected benefits. Indeed, EPA's own modeling showed that the emission reductions required of upwind states under the CSAPR Update Rule are disproportionate to the relatively limited projected reductions in downwind ozone concentrations that the rule's emission limits are estimated to produce.[15] Furthermore, if left unmodified, the CSAPR Update Rule threatens jobs in the energy sector because its stringent emission caps can be expected to have the effect of restricting fuel choice.

UARG filed its petition for reconsideration of the CSAPR Update Rule with EPA on December 23, 2016. At least eight other petitions for reconsideration of the rule are pending before EPA.[16] The CSAPR Update Petition describes several aspects of the rule that EPA should reconsider, including: (i) EPA's reliance on modeling projections to identify downwind areas to be addressed by the rule, in disregard of real-world air quality conditions;[17] (ii) EPA's use of an unjustifiably low one-percent-of-NAAQS "contribution threshold" to "link" upwind states to downwind receptors and thereby to subject those states to additional regulation under the rule;[18] and (iii) EPA's failure, in conducting its air quality modeling, to properly account for effects of emissions from non-U.S. sources, which no state has the authority or ability to regulate.[19] Additional background regarding concerns with EPA's CSAPR Update Rule methodology is provided in the CSAPR Update Petition and in UARG's rulemaking comments submitted to

---

[14] 81 Fed. Reg. 74,504 (Oct. 26, 2016).

[15] *See* UARG's Petition for Partial Reconsideration of the CSAPR Update Rule at Section X (Dec. 23, 2016) ("CSAPR Update Petition"), https://www.epa.gov/sites/production/files/2017-01/documents/the_utility_air_regulatory_group_0.pdf.

[16] *See* https://www.epa.gov/airmarkets/petitions-reconsideration-received-csapr-update.

[17] CSAPR Update Petition at Sections I & II.

[18] *Id*. at Section III.

[19] *Id*. at Section IV.

EPA on the December 2015 proposed version of the CSAPR Update Rule.[20] In addition, several petitions for judicial review of the CSAPR Update Rule have been filed and are pending in the U.S. Court of Appeals for the D.C. Circuit, including petitions for review filed by UARG, Murray Energy Corporation, many other industry parties, and several states (Alabama, Arkansas, Ohio, Texas, Wisconsin, and Wyoming) (*Wisconsin v. EPA*, No. 16-1406 & consolidated cases).

EPA should promptly reconsider and modify key elements of the CSAPR Update Rule, as identified in UARG's CSAPR Update Petition, to alleviate unnecessary, costly, and counterproductive regulatory burdens.[21] In doing so, EPA should, for example, consider, propose, and promulgate changes that would increase the levels of states' emission budgets based on corrections to and further review of the existing rule, as well as changes that would appropriately reform EPA's methodology for addressing interstate transport, as described in the attached CSAPR Update Petition and UARG's rulemaking comments.[22] In addition, based on its review and reconsideration of the CSAPR Update Rule and its methodology, EPA should, to the extent supported by appropriate analysis, issue a determination identifying states that currently are subject to that Rule but that do not contribute significantly to nonattainment of the 2008

---

[20] *See* UARG Comments on Proposed CSAPR Update Rule (Feb. 1, 2016), EPA-HQ-OAR-2015-0500-0253. UARG also submitted supplemental comments on June 1, June 9, and August 16, 2016, addressing information that became available after the deadline for submitting comments on the proposed rule. UARG's supplemental comments are attached to the CSAPR Update Petition as Appendix A to that document.

[21] UARG emphasizes that it will be important for EPA, as it reconsiders the CSAPR Update Rule, to ensure that states may continue to rely on compliance with the NOx and sulfur dioxide ("SO_2") emission limits in CSAPR itself to satisfy "best available retrofit technology" ("BART") requirements for EGUs under the CAA's visibility protection program, as provided in 40 C.F.R. § 51.308(e)(4) (as promulgated at 77 Fed. Reg. 33,642, 33,656 (June 7, 2012)). *See also* 81 Fed. Reg. 78,954, 78,961-64 (Nov. 10, 2016) (describing EPA's sensitivity analysis reaffirming the validity of the Agency's determination that participation in CSAPR is a valid BART alternative).

[22] As noted in the CSAPR Update Petition, EPA in reviewing and reconsidering the CSAPR Update Rule should not make any change that would result in imposition of an ozone-season NOx emission budget for any state that is more stringent than the budget for that state under the existing rule. EPA also should not make any change that would affect the continuing validity and effectiveness of the parts of the CSAPR Update Rule in which EPA determined that: (i) Florida, North Carolina, and South Carolina are excluded from the ozone-season NOx program under both the original CSAPR and the CSAPR Update Rule; and (ii) Georgia is not subject to any obligations with respect to interstate transport for ozone NAAQS beyond those established for that state in CSAPR itself.

ozone NAAQS in (and do not interfere with maintenance of that NAAQS by) any other state and, consequently, remove those states from coverage under the CSAPR Update Rule.

III. Regional Haze and Other Visibility Regulations

EPA should reconsider and modify certain aspects (described below) of its January 10, 2017 visibility rule revisions that, if left unmodified, will impose unnecessary and counterproductive regulatory costs and other burdens.

Sections 169A and 169B of the Act and EPA regulations at 40 C.F.R. §§ 51.300-51.309 require states to adopt and submit state implementation plans ("SIPs") to achieve "reasonable progress" toward a national goal of preventing and remedying impairment of visibility in certain national parks and wilderness areas, to the extent visibility impairment in those areas results from manmade air pollution. The CAA's visibility program generally requires states to evaluate emission sources or source categories for potential emission controls to help achieve reasonable progress. Although Congress intended that states be the principal decisionmakers in this area, in many instances over the past eight years, EPA improperly assumed the states' role.

During the first "planning period" under the visibility program's "regional haze" provisions—a period that began in 2008 and will end in 2018—the primary regulatory driver was the CAA's BART requirement applicable to many EGUs and industrial sources. Now that decisionmaking on BART is complete for most states, the main focus of the upcoming second planning period, which will run from 2018 to 2028, will be implementation of the CAA's reasonable progress requirement.

EPA substantially amended many elements of its visibility protection regulations in its January 10, 2017 rule.[23] Contrary to the version of that final rule as signed on December 14, 2016 (which would have taken effect 30 days after publication in the *Federal Register*), the final rule as published on January 10 was made effective immediately in order to evade the incoming Administration's normal regulatory review and its "regulatory freeze" pending that review. The January 10 rule is the subject of three petitions for administrative reconsideration filed with EPA and eleven petitions for review in the U.S. Court of Appeals for the D.C. Circuit (*Texas v. EPA*, No. 17-1021 and consolidated cases). UARG filed a petition for administrative reconsideration[24] and a petition for judicial review of the rule. EPA has not yet responded to UARG's petition for reconsideration. As described below and in the Visibility Rule Petition, the rule has several provisions that EPA should now reconsider and repeal or modify.

[23] 82 Fed. Reg. 3078 (Jan. 10, 2017).

[24] *See* UARG Petition for Partial Administrative Reconsideration of Amended Visibility Requirements (Mar. 13, 2017) ("Visibility Rule Petition") (attached as Exhibit 1).

When Congress enacted the CAA's visibility provisions, it made clear the states have broad discretion in implementing the program. The D.C. Circuit recognized that principle in the leading case in this area, *American Corn Growers Ass'n v. EPA*, 291 F.3d 1 (D.C. Cir. 2002). As the program was implemented during the previous administration, however, EPA frequently failed to give the deference that it owed to state decisions and often supplanted reasonable state regulatory plans with more stringent and costly federal control requirements in many states, including Arizona, Arkansas, Nebraska, New Mexico, North Dakota, Oklahoma, Texas, Utah, and Wyoming.

To address these problems, EPA should modify its January 10, 2017 regional haze rules to emphasize the breadth of state authority and to make clear EPA will not second-guess state determinations. EPA should do this by, for instance, making clear that states are free to decide how to consider and assess each of the statutory "reasonable progress" factors, including the costs associated with additional emission controls, and whether visibility improvements resulting from further controls will be substantial enough to warrant imposing those controls.

Although some parts of the January 10, 2017 rule make common-sense revisions that should be preserved—such as a three-year extension, from July 2018 to July 2021, of states' deadline to develop and submit SIPs for the second planning period—other parts of that rule create problems that require additional regulatory action to make necessary modifications. For example, the rule purports to impose on states an improper interpretation—adopted in the last Administration, over many stakeholders' objections—of the relationship between two key elements of the regional haze program: the requirement that states determine and adopt "reasonable progress goals" and the requirement that states identify specific emission control measures to include in "long-term strategies" to achieve reasonable progress. The January 10, 2017 rule requires states to first identify all measures to be included in the state's long-term strategy and then to calculate reasonable progress goals based on the degree of visibility improvement that computer modeling projects those measures will achieve. This aspect of the rule subverts the normal regulatory process by making states' determinations of reasonable progress goals an afterthought and compelling states to consider regulation even where it is unnecessary to stay on track toward reasonable visibility objectives. States should instead be free to develop reasonable progress goals they deem appropriate for a given area and then to determine which specific measures should be included in long-term strategies to achieve those goals.

The January 10, 2017 rule also has several other provisions that EPA should reconsider and modify—including (among others) provisions concerning the "uniform rate of progress" and provisions addressing states' consultation processes with other states and with federal land management agencies. A detailed description of how EPA should address and reform these and other aspects of the rule is in UARG's Visibility Rule Petition.[25]

Consistent with Executive Order 13777, revising EPA's visibility rules as recommended in this comment letter and in UARG's Visibility Rule Petition would alleviate unnecessary regulatory burdens and would be consistent with applicable law. Such revisions would advance the Executive Order's objective of avoiding regulation that unnecessarily imposes costs that outweigh benefits and that inhibit job creation and economic growth.

IV. Regulation of Hazardous Air Pollutants

A. Compliance Provisions of the Mercury and Air Toxics Standards ("MATS") Rule, codified at 40 C.F.R. Part 63, Subpart UUUUU

The MATS Rule, regulating hazardous air pollutants from coal and oil-fired electric generating units, is among the most expensive and burdensome rules EPA has ever promulgated. Although the most significant costs associated with the rule derive from purchase, installation, and use of emission control technologies, the task of demonstrating compliance under the rule through periodic performance testing, continuous emissions monitoring, recordkeeping, and reporting also is costly. Some of those compliance demonstration costs are unavoidable, but other costs and burdens are avoidable. Rules that are written clearly and that offer flexibility—where that can be achieved without sacrificing environmental protections—provide the greatest "net benefit." Unfortunately, the MATS Rule has many provisions that are internally inconsistent, ambiguous, or inflexible, each of which adds significantly to the cost and burden of complying with the rule.

Although the current rule is the product of multiple rulemakings over a period of more than 5 years, those successive rulemakings have not fully addressed the rule's overall compliance burdens. The 2012 rule contained numerous errors and problems, many of which are described in detail in UARG's first petition for administrative reconsideration.[26] When EPA conducted a reconsideration rulemaking on a few of the issues in the rule pertaining to periods of startup and

---

[25] As noted above and in the Visibility Rule Petition, one provision of the January 10, 2017 rule is an adjustment, from July 2018 to July 2021, of the deadline by which states must submit SIPs for the second planning period. UARG joins numerous states and other stakeholders in supporting that deadline adjustment and urges EPA *not* to reconsider that element of the rule.

[26] *See* UARG Petition for Reconsideration of MATS Rule at Section VI (Apr. 16, 2012), EPA-HQ-OAR-2009-0234-20180.

shutdown, the Agency's 2014 reconsideration rule created more problems than it resolved.[27] UARG raised those problems and other longstanding issues in comments on the Agency's 2015 proposed "Technical Corrections" to the MATS Rule.[28] Although EPA resolved some of the issues from the prior two rulemakings in its 2016 Technical Corrections rule, a lot of work remains to be done to make the rule clear, consistent, and appropriately flexible. Even after improvements to the rule in the Technical Corrections, facilities are struggling to interpret and reconcile ambiguous and inconsistent provisions. They also remain subject to overly restrictive requirements for the conduct of performance tests that could result in operation of units that otherwise would not operate, simply to conduct tests to measure emissions. This is unnecessary, costly, and grossly inefficient.

EPA currently is in the middle of another MATS-related rulemaking, this one focused on improving the electronic reporting requirements of the MATS Rule by allowing all reports to be submitted using the Emissions Collection and Monitoring Plan System ("ECMPS") software system already used by utilities under the Acid Rain Program and CSAPR. Although UARG supports that change, UARG members are concerned that the burdens associated with some of the very detailed electronic reporting EPA has proposed will outweigh the cost savings associated with the move to ECMPS. EPA and utilities also cannot successfully implement the electronic reporting requirements without a common understanding of what other substantive compliance provisions in the rule require. As a result, in comments on that proposal, UARG again asked EPA to resolve some of the issues UARG has identified in the existing rule, in addition to requesting changes in the volume of new information EPA has proposed be submitted electronically.[29]

The MATS Rule has the potential to be less costly. EPA should use the opportunity of the ongoing rulemaking to work with UARG to achieve that end by resolving the issues that remain in the existing rule's compliance procedures, and addressing UARG's concerns about the proposed revisions.

[27] EPA ultimately denied reconsideration on the remainder of UARG's 2012 petition without addressing the merits of UARG's concerns regarding the compliance provisions, concluding only that it had met its procedural obligations under CAA § 307(d)(7) to solicit comment on the rule. EPA, Denial of Petitions for Reconsideration of Certain Issues: MATS and Utility NSPS (Mar. 2015), EPA-HQ-OAR-2009-0234-20493.

[28] *See* UARG Comments on Proposed Technical Corrections (Apr. 3, 2015), EPA-HQ-OAR-2009-0234-20483.

[29] *See* UARG Comments on Proposed MATS Electronic Reporting Rule (Nov. 15, 2016), EPA-HQ-OAR-2009-0234-20609.

B. Renewed Analysis of Potentially Delisting Natural Gas-Fired Stationary Combustion Turbines from Regulation Under CAA Section 112

Gas-fired combustion turbines make up a large and growing portion of the nation's electric generating fleet, and they are an essential part of maintaining electric reliability in the United States. But for over a decade these sources have been in legal limbo with respect to their regulatory status under the CAA's regulatory provisions governing hazardous air pollutants ("HAPs"). The resulting uncertainty presents risks to combustion turbine owners that should be addressed by EPA.

EPA listed stationary combustion turbines as a source category for regulation under section 112 of the Act in 1992 and promulgated emission standards limiting HAP emissions from new and reconstructed turbines in 2004.[30] However, almost immediately, EPA proposed to remove natural gas-fired combustion turbines from the list of sources subject to regulation under section 112.[31] Based on EPA's own analysis and on a petition for delisting submitted by the Gas Turbine Association, the Agency made a preliminary finding that gas-fired turbines meet the CAA's health-protective criteria for delisting.[32]

EPA's 2004 analysis found that even using conservative assumptions about exposure and risk, emissions from gas-fired combustion turbines would meet these health-protective statutory criteria. Accordingly, EPA proposed to delist gas-fired turbines from section 112 regulation. Recognizing that it would be irrational to require compliance with a rule it intended to revoke, EPA also issued a stay of the emission standards for gas-fired turbines until the Agency could take final action on its delisting proposal.[33]

However, EPA never took final action on its delisting proposal. According to the terms of the stay, if EPA ultimately decides not to delist gas-fired turbines, then the standards will spring into effect for any turbine built after January 2003. This twelve-year waiting period has generated significant regulatory uncertainty for owners of gas-fired combustion turbines, who cannot say for certain whether or not their turbines built in the interim must comply with the emission standards. That uncertainty is compounded by EPA's upcoming Risk and Technology

[30] 69 Fed. Reg. 10,512 (Mar. 5, 2004).
[31] 69 Fed. Reg. 18,327 (Apr. 7, 2004).
[32] *Id.*; *see* CAA § 112(c)(9)(B) (describing criteria).
[33] 69 Fed. Reg. 51,184 (Aug. 18, 2004).

Review ("RTR") for stationary combustion turbines: turbine owners cannot be sure whether EPA will further tighten the standards that might ultimately apply if the stay is lifted.[34]

EPA should revisit its delisting proposal for gas-fired combustion turbines and assess whether those sources still meet the statutory criteria for delisting. The Agency's previous review showed that gas-fired turbines' HAP emissions posed minuscule risks to health and the environment. If the delisting criteria are still satisfied, EPA should promptly delist gas-fired turbines from regulation under section 112.[35] If gas-fired turbines are not delisted, the Agency should, as appropriate, provide for a transition mechanism for gas-fired turbines constructed since 2003, and EPA should be careful in the RTR proceeding not to impose revised standards that would be unduly burdensome and costly.

C. National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards for Stationary Reciprocating Internal Combustion Engines ("RICE"), codified at 40 C.F.R. Part 60 Subparts IIII and JJJJ and 40 C.F.R. Part 63 Subpart ZZZZ

EPA has promulgated a set of interrelated regulations for emissions from RICE units pursuant to both CAA § 111 (new source performance standards) and § 112 (national emissions standards for HAPs). Each set of rules identifies numerous subcategories of internal combustion engines and applies varying requirements to each subcategory based on age, size, fuel type, engine design, use, and other factors. The overlapping regulatory programs and range of subcategories have resulted in a complex set of requirements that can be difficult for source owners to navigate.

The RICE regulations generally require manufacturers to install cost-effective state-of-the-art technology to minimize emissions. UARG agrees that requiring manufacturers (rather than source owners or operators) to install these controls is a reasonable approach to regulation for these sources. But EPA has also promulgated extensive and burdensome testing, maintenance, and record-keeping requirements for owners and operators. These requirements

[34] A federal court recently set a March 2020 deadline for EPA to complete its RTR for stationary combustion turbines (along with 19 other source categories). *Cal. Cmtys. Against Toxics v. Pruitt*, No. 15-cv-512 (TSC), 2017 WL 978974 (D.D.C. Mar. 13, 2017).

[35] Although the D.C. Circuit has ruled that CAA § 112(c)(9)(B)(i) only allows EPA to delist entire source categories (rather than subcategories), *see NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007), nothing in the Act prohibits EPA from reclassifying gas-fired combustion turbines as a separate source category and delisting them. *See* CAA § 112(c)(1).

impose substantial costs with little to no benefit. Emissions from RICE sources are already small and do not warrant these onerous and needless regulations.

For example, EPA has placed unnecessary restrictions on the operation of emergency engines. These engines are limited to just 50 hours of non-emergency operation, which count toward the 100 hour annual limit for testing and maintenance. Tracking these independent uses of RICE sources is burdensome and achieves no benefit. In addition, the work practice standards for most RICE sources require servicing the unit more often than manufacturer specifications, which is inefficient and does not provide environmental benefits. Finally, for new Tier 4 engines, EPA adopted redundant requirements for both manufacturers and operators restricting operation when certain emission controls are not working properly, which serve only to hinder operators' ability to address emergency situations. These provisions are burdensome, threaten reliability, and inappropriately place manufacturers in the role of policing emergency situations.

EPA should eliminate the unnecessary requirements applicable to RICE sources and adopt clear, streamlined replacements.

V. Preconstruction Permitting Issues

A. New Source Review ("NSR") Reform

The Act's NSR program requires major stationary sources to go through an extensive, time-consuming, and costly review and permitting process prior to construction. The NSR program also applies to existing facilities if they are modified in substantial ways and if, as a result, emissions increase by significant amounts (these are known as "major modifications"). The NSR program requires, among other things, that the owner or operator of a proposed new major source or a proposed major modification obtain a pre-construction permit, which will be issued only if the owner/operator (i) demonstrates—normally through air quality modeling—that the proposed major new source or modification will not cause or contribute to a violation of air quality standards; (ii) installs the best available control technologies ("BACT") to reduce levels of specific regulated pollutants, and (iii) demonstrates that the proposed new source or modification will not cause an adverse impact on air quality-related values in federally protected lands (*e.g.*, national parks or wilderness areas).

For the first two decades of the NSR program, existing sources rarely triggered it. That is because EPA applied it in a way to be triggered only by unusual projects that would expand the capacity of the source—i.e., projects that create *new* sources of emissions. It is also because NSR is so time-consuming and expensive that sources generally avoided activities that would expand their capacities *because* they could trigger NSR.

Starting in the late 1990s, however, EPA's enforcement arm, in an effort to drive policy, filed and/or threatened a large number of lawsuits to force the installation of controls not otherwise required by the Act. To achieve this goal, EPA asserted in the lawsuits a theory of universal liability: any maintenance project—anything larger than day-to-day activity akin to changing a car's oil—is a "change" that could trigger NSR; and any such "change," if it addresses reliability, availability, or efficiency issues that the plant might have experienced in the recent past, according to the lawsuits, will "increase" total emissions as compared to the recent past and therefore will trigger NSR. More than a decade and half later, these types of lawsuits continue, with no certainty as to how the NSR program will apply to existing plants. For example, courts have reached diametrically opposite conclusions with respect to whether similar projects are considered routine maintenance, repair, and replacement ("RMRR") and thus excluded from NSR.[36] EPA's latest revision of the emissions increase provisions has, in a single case, generated five different opinions as to how these provisions should apply.[37] At a minimum, the fact that courts—and even judges within the same court—cannot agree on what these regulations mean and how they should apply in particular circumstances highlights the uncertainty these regulations have created and how inefficient their application has been in the recent past.

The NSR rules, as EPA's enforcement arm has sought to apply them to existing facilities for the last decade and a half, discourage—and potentially impose very large costs on—needed projects to maintain and improve existing plants' availability, reliability, safety, and efficiency. Those are precisely the types of projects that maintain American industry's competitiveness and are needed to cost-effectively maintain the reliability of the nation's energy systems. For these reasons, the NSR rules should be revised to remove the uncertainty surrounding their applicability and the perverse incentives they create.

B. Synthetic Minor Sources

Current NSR regulations contain a provision (40 C.F.R. § 52.21(r)(4)) stating that a synthetic minor source—i.e., a source or modification that took operational or other limitations

[36] *Compare, e.g.*, *Nat'l Parks Conservation Ass'n v. TVA*, No. 3:01-CV-71, 2010 WL 1291335 (E.D. Tenn. Mar. 31, 2010) (finding economizer and superheater replacements RMRR); *with United States v. La. Generating LLC*, No. 09-100-JJB-CN, 2012 WL 4107129, at *4 (M.D. La. Sept. 19, 2012) (finding reheater replacements not RMRR).

[37] *See United States v. DTE Energy Co.*, 845 F.3d 735 (6th Cir. 2017) (three different opinions), 711 F.3d 643 (6th Cir. 2013) (two different opinions). The Sixth Circuit recently denied DTE Energy's petition for rehearing en banc, and currently has pending before it DTE Energy's motion to stay the mandate pending the filing of a petition for certiorari.

to remain minor—becomes subject to NSR when it "becomes a major source or major modification solely by virtue of relaxation in any enforceable limitation" established in a federally enforceable air permit. This provision was placed in the NSR regulations to prevent circumvention of those regulations—that is, sources taking limitations to avoid NSR review when they are constructed, only to seek to relax these limitations a short period thereafter.

That provision is too broad, however, in that it sweeps into its scope circumstances in which EPA's concerns about circumvention are clearly not implicated: for example, a situation in which a relaxation of the permit limits may be sought years after the initial construction. As a result, this rule unnecessarily limits production and hinders economic growth, even though the increase in emissions from the later construction is very small and would have a *de minimis* impact (i.e., even though the proposed change itself is not major). In the utility industry, the result is that generation is shifted to higher cost units, unnecessarily increasing costs for ratepayers and, in all likelihood, resulting in more (not less) emissions.

This "relaxation" provision should be revised such that it does not apply in situations in which the risk of circumvention is very unlikely or nonexistent. For example, EPA should consider whether, after a certain amount of time has passed (such as five or more years after a permit containing the operational limitation was issued), the relaxation provision should no longer apply. In these circumstances, a proposed physical or operational change should be analyzed under the base NSR rules, as it would be for any other "true" minor source or modification. Such a change to the regulations would sensibly encourage economic growth while simultaneously ensuring that any physical or operational change that is a major source or modification in its own right would be subject to preconstruction review.

C. Prevention of Significant Deterioration ("PSD") Significant Emissions Rate for Greenhouse Gases

In *UARG v. EPA*,[38] the Supreme Court held that EPA's so-called "Tailoring Rule" was unlawful in as much as it would apply the PSD and Title V permitting programs to sources based solely on their GHG emissions. Instead, the Court held, EPA's authority to regulate GHGs under PSD and Title V extends only to "anyway" sources, that is, sources that otherwise would trigger these permitting requirements for non-GHG pollutants. For these "anyway" sources, EPA could require BACT for GHGs "only if the source emits more than a *de minimis* amount of greenhouse gases."[39] On remand, EPA proposed to establish its previous Tailoring Rule threshold, 75,000 tons per year, as that *de minimis* level or "Significant Emissions Rate" (also known as a

---

[38] 134 S. Ct. 2427 (2014).
[39] *Id.* at 2449.

significance threshold).[40] UARG and its members filed comments supporting EPA's authority to establish a significance threshold on *de minimis* grounds, but objecting to the proposed rule's approach of merely reverse-engineering a pre-determined result—namely, the Tailoring Rule's 75,000 tons per year level—instead of applying the correct legal standard for *de minimis* authority and properly evaluating the facts and data in the record under that standard.[41] Indeed, as UARG's comments explained, applying EPA's historic and well-established approach would have yielded a significance threshold of 320,000 tons per year, four times higher than EPA's predetermined, "preferred" result. Yet, not only did the proposed rule reject any significance threshold higher than 75,000 tons per year, it arbitrarily declared that EPA would not even accept comments on such higher thresholds.

Establishing an appropriate PSD *de minimis* level for GHGs falls squarely in the category of action that would alleviate unnecessary, costly, and counterproductive regulatory burdens. EPA should withdraw the current proposal, and propose a new, higher significance threshold for GHGs.

VI. New Source Performance Standards ("NSPS") Issues

A. Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills, 81 Fed. Reg. 59,276 (Aug. 29, 2016), codified at 40 C.F.R. Part 60, Subpart Cf

UARG urges EPA to grant petitions for reconsideration that are pending before the Agency regarding this rule, which revised the existing emissions guidelines for municipal solid waste landfills to make them more stringent. Although EPA possesses authority to amend regulations to correct mistakes or to streamline processes as part of its authority under section 111(d), the Agency lacks authority under that provision to revise its emission guidelines to direct states to make previously promulgated standards of performance for existing sources more stringent. UARG filed comments on EPA's proposed revision to the emission guidelines that are available in the rulemaking docket.[42] UARG is also challenging this rule (along with other Petitioners) in the U.S. Court of Appeals for the District of Columbia Circuit (*Nat'l Waste & Recycling Ass'n v. EPA,* No. 16-1371 and consolidated cases).

---

[40] 81 Fed. Reg. 68,110 (Oct. 3, 2016).

[41] UARG Comments on Proposed Significance Threshold (Dec. 16, 2016), EPA-HQ-OAR-2015-0355-0089.

[42] *See* UARG Comments on Proposed Emission Guideline Revisions for Municipal Solid Waste Landfills (Oct. 26, 2015), EPA-HQ-OAR-2014-0451-0198.

B. Electronic Reporting Under the NSPS, codified at 40 C.F.R. Part 60

New source performance standards establish federally enforceable emission standards and related compliance requirements for new, modified, and reconstructed facilities in specific source categories.[43] NSPS are established by EPA, but their implementation and enforcement usually are delegated to state agencies. Reporting requirements for the NSPS are established in the general provisions in Subpart A and in individual subparts. The general provisions currently require duplicate reporting to EPA Regional Offices and delegated state agencies, generally in hard copy (although use of electronic media also is permitted for submissions to state agencies with their consent).

Electronic reporting of information to a centralized data system has the potential to reduce costs and burdens and improve accessibility of information to regulators, the regulated entities, and the public. Unfortunately, EPA's implementation of such reporting under the NSPS has done the opposite.

Beginning in 2009, EPA started inserting into individual subparts of the NSPS a requirement that facilities electronically submit certain reports to EPA using an EPA-designed software system and website that the Agency was in the process of developing. The first of those requirements took effect July 1, 2011.[44] The requirement to submit existing reports electronically to a central location has not been controversial. However, the software system EPA has specified (called the "Electronic Reporting Tool" or "ERT") is controversial because the program is outdated and difficult to use, and because it requires submission of significant volumes of information that are not necessary to demonstrate compliance with any applicable NSPS.[45] EPA's failure to relieve sources from existing duplicate paper reporting requirements also generated objections.

---

[43] UARG members own and operate facilities subject to many NSPS subparts, including those applicable to steam generating units (Subparts D, Da, Db, and Dc), combustion turbines (Subparts GG and KKKK), coal preparation plants (Subpart Y), and nonmetallic mineral processing plants (Subpart OOO).

[44] *See, e.g.*, 40 C.F.R. § 60.49a(v)(4) (Subpart Da), § 60.46b(j)(14) (Subpart Db), § 60.45c(c)(14) (Subpart Dc), § 60.258(d) (Subpart Y).

[45] EPA has said it is collecting the additional information to assist in development of emission factors. Initially, EPA collected the information simply by mandating use of the ERT software. However, in 2016, EPA revised the general provisions to codify some of those reporting requirements. 81 Fed. Reg. 59,800 (Aug. 30, 2016) (revising 40 C.F.R. § 60.8(f)).

In 2015, EPA proposed to expand the electronic reporting requirement to all but a few NSPS subparts by revising the general provisions.[46] UARG's objections to the ERT and EPA's proposed expansion of the requirement are described in detail in UARG's comments on that proposal.[47]

On December 21, 2016, EPA Administrator Gina McCarthy signed a final rule that would impose many of the burdens to which UARG and others objected. The rule has not yet been published. Although that rule includes some extended deadlines, multiple promises to develop alternatives to the use of the ERT, and other improvements as a result of comments, the basic mandate of the rule is the same. If the rule becomes effective, numerous facilities will be required (at least in the short term) to electronically report significant volumes of information to EPA using the ERT, in addition to providing the same information in hard copy to any delegated state that does not waive the duplicate reporting requirement. The final rule also includes drafting errors that would inadvertently impose the new requirements on facilities EPA said it planned to exclude from the rule. If the rule is published, UARG intends to petition for administrative reconsideration.

The current NSPS electronic reporting requirements, and the planned expansion of those requirements to include many additional subparts, do not provide a "net benefit." EPA should formally withdraw the signed final rule and issue a new proposal to replace existing requirements for reporting using the ERT with a more workable electronic reporting system and to reduce the volume of information that must be reported electronically. For electric utilities, EPA should consider adapting its existing ECMPS software, which already is used by utilities to report information under the Acid Rain Program and CSAPR, to collect any additional information needed for those sources to demonstrate compliance with an applicable NSPS. As discussed further in Section IV.A above, EPA already is doing that for the MATS Rule at 40 C.F.R. Part 63, Subpart UUUUU.

Finally, EPA should act expeditiously—perhaps by direct final rule—to authorize use of electronic reporting (including email submission of electronic media) to EPA Regional Offices and to remove requirements for duplicate reporting to EPA Regions of information already electronically reported to EPA (e.g., to ECMPS or EPA's Central Data Exchange),

---

[46] 80 Fed. Reg. 15,100 (Mar. 20, 2015).

[47] *See* UARG Comments on Proposed NSPS Electronic Reporting Rule (June 18, 2015), EPA-HQ-OAR-2009-0174-0093.

C. Reconsideration of the NSPS for Stationary Combustion Turbines, codified at 40 C.F.R. Part 60, Subpart KKKK

EPA promulgated the NSPS for new, modified, and reconstructed stationary combustion turbines in July 2006 as Subpart KKKK.[48] UARG filed a petition for administrative reconsideration of that rule raising several objections, including that (i) the rule's NOx standards were unachievable for large gas-fired turbines operating in simple cycle mode, (ii) the rule failed to provide a methodology to calculate compliance for operating periods when several different standards apply, and (iii) several other issues related to emissions monitoring.[49]

EPA agreed to reconsider the Subpart KKKK rule and issued a proposed reconsideration rule in August 2012.[50] Instead of simply addressing UARG's reconsideration request, EPA proposed an almost complete rewrite of the rule, creating many new problems. At the same time, the proposal failed to actually address some of the specific issues UARG raised in its reconsideration petition. Further, EPA proposed to radically alter the analysis used to determine whether an existing combustion turbine had been "reconstructed," such that commonplace, insignificant work regularly performed at turbine facilities could subject those units to the stringent standards in Subpart KKKK. UARG submitted comments explaining its objections to the proposed changes to the reconstruction analysis and other problematic aspects of the proposal.[51] EPA never finalized its proposed reconsideration rule.

EPA's proposed reconsideration rule has subjected combustion turbine owners to considerable regulatory uncertainty, making it difficult for them to anticipate the legal consequences of necessary maintenance activities or to predict what standards their turbines will ultimately need to comply with. UARG urges the Agency to address this uncertainty by issuing a supplemental proposal on reconsideration of Subpart KKKK that withdraws the 2012 proposal's changes to the reconstruction analysis and that addresses in full the issues in UARG's petition for reconsideration and its comments on the 2012 proposed rule.

---

[48] 71 Fed. Reg. 38,482 (July 6, 2006).

[49] *See* UARG Petition for Reconsideration of Subpart KKKK Rule (Sept. 7, 2006), EPA-HQ-OAR-2004-0490-0325.

[50] 77 Fed. Reg. 52,554 (Aug. 29, 2012).

[51] *See* UARG Comments on Subpart KKKK Reconsideration Proposal (Dec. 28, 2012), EPA-HQ-OAR-2004-0490-0418.

D. Reconsideration of the NSPS for Coal Preparation and Processing Plants, codified at 40 C.F.R. Part 60, Subpart Y

EPA promulgated revisions to the NSPS for coal preparation and processing plants in October 2009.[52] UARG filed a limited petition for reconsideration of these Subpart Y revisions, noting that the rule was vague as to how one could determine whether an existing coal pile had been "modified" or "reconstructed" and thus become subject to Subpart Y.[53] Because coal piles are always in flux and their emissions are difficult to measure, it is unclear how EPA would determine whether an emissions rate increase occurs for the purposes of modification, or what components would be included in a reconstruction analysis. UARG also asked EPA to reconsider its imposition of the burdensome electronic reporting requirements discussed above in Section VI.B. EPA agreed to reconsider those issues but has never issued a proposed reconsideration rule.

EPA's continued failure to address the treatment of existing coal piles under Subpart Y has created substantial regulatory uncertainty within the industry, making it difficult for them to predict how certain activities at their coal piles might trigger the requirements of Subpart Y. UARG urges the Agency to issue a proposed rule responding to UARG's reconsideration petition that clarifies how existing coal piles will be treated under Subpart Y and adopts a more reasonable mechanism for electronic reporting..

E. Revisions to Test Method for Determining Stack Test Gas Velocity Taking Into Account Velocity Decay Near the Stack Walls

In 2009, EPA proposed revisions to Test Method 2H in 40 C.F.R. Part 60, Appendix A, that would reduce regulatory burdens associated with emissions testing.[54] The proposal would incorporate into Method 2H a procedure in Conditional Test Method 041 the use of which EPA was already routinely approving through source-by-source petitions. The proposal, which would make the method more accurate and require less testing, was universally supported and technically sound.[55] UARG asked EPA to move expeditiously to finalize the revisions in order to eliminate the need for source-by-source petitions. More than seven years later, the proposal has yet to be finalized. UARG urges EPA not to delay any further and finalize the revisions as proposed.

[52] 74 Fed. Reg. 51,950 (Oct. 8, 2009).
[53] *See* UARG Petition for Reconsideration of Subpart Y Rule (Dec. 7, 2009).
[54] 74 Fed. Reg. 42,819 (Aug. 25, 2009).
[55] *See, e.g.* UARG Comments on Test Method 2H Revisions (Oct. 26, 2009), EPA-HQ-OAR-2008-0697.

VII. National Ambient Air Quality Standards

A. "Findings of Substantial Inadequacy" of SIPs and "SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction," published at 80 Fed. Reg. 33,840 (June 12, 2015)

In 2015, EPA Administrator Gina McCarthy in one action issued a group of "SIP Calls" mandating that 36 states revise their previously EPA-approved SIPs, because certain provisions of those SIPs addressing emissions from industrial sources during periods of startup, shutdown, or malfunction of applicable process or control equipment ("SSM") are inconsistent with EPA's most recent interpretations of certain CAA provisions. The SIP Calls are not based on any finding of air quality impacts or finding that removing the provisions is necessary to meet other CAA goals. Rather, they are based on the conclusion that there is a "facial inconsistency" of the called SIP provisions' language with EPA's recent interpretations of certain CAA provisions, and that inconsistency renders the previously EPA-approved SIPs "substantially inadequate."

Under the CAA, states have primary responsibility for attaining, maintaining, and enforcing the NAAQS through their SIPs and EPA has only a secondary role that provides no authority to force states to adopt specific control measures. The SIP Calls are inconsistent with that system of cooperative federalism. The SIP Calls also are inconsistent with agencies' inherent responsibility to consider costs and benefits when exercising discretionary authority. UARG is currently a petitioner challenging the SSM SIP Call in the U.S. Court of Appeals for the D.C. Circuit, and the opening briefs that Industry Petitioners (including UARG), State Petitioners, and Texas Petitioners filed are available in the docket for those consolidated cases.[56]

The called SIP provisions are all designed to address the inability of sources to meet otherwise applicable emission control requirements under certain operating conditions, like SSM periods. All of the states subject to the SIP Calls have submitted (or, for revised NAAQS, will submit) demonstrations establishing that their SIP will result in attainment of the NAAQS. Many of the subject states already are achieving some or all of the NAAQS through their existing SIPs. On the other hand, the SIP Calls have imposed on states, and on EPA, the obligation to embark on a years-long and costly process of review and approval/disapproval of revised state rules and potentially development of Federal Implementation Plans. Imposition of such costs, in the absence of quantifiable benefits, also is contrary to the goals of Executive Order 13777.

[56] *See Walter Coke, Inc. v. EPA*, No. 15-1166 (D.C. Cir. Oct. 31, 2016), ECF Nos. 1643502, 1643571, 1643769.

In short, the SIP Calls interfere with state discretion and impose significant costs and burdens without any corresponding finding of air quality-related benefit. EPA should convene a proceeding to withdraw the SSM SIP calls by applying a SIP call standard that is consistent with its limited authority under the CAA and obligation to consider the impacts of its exercise of that authority.

B. NAAQS Promulgation and Implementation

NAAQS and their implementation are at the heart of the CAA. EPA sets the NAAQS and must review them at least every five years, revising them as appropriate. Unfortunately, when the NAAQS for a particular pollutant are revised, previous NAAQS for that pollutant seem to linger forever in scattered sections of the Code of Federal Regulations. For example, NAAQS for fine particulate matter ("$PM_{2.5}$") are found in sections 50.7, 50.13, and 50.18 of 40 C.F.R. Part 50. Such scattered codification of NAAQS is at best confusing and at worst misleading. UARG recommends revision of 40 C.F.R. Part 50 to remove NAAQS that have been replaced and to consolidate the current NAAQS for each regulated pollutant in a single section of the C.F.R.

UARG also urges the Agency to consider changes that would simplify the process that it uses to set and revise NAAQS. For example, the present process involves preparation by EPA's career staff of a Policy Assessment. This document is not required by the Act. It could be eliminated, modified to reflect senior management input, or replaced by an Advance Notice of Proposed Rulemaking as was planned in 2006.[57] In addition, to the extent that risk assessment remains a part of the process, UARG urges that the assessment fully capture uncertainty about the estimated number and quality of effects. Preparation of an Integrated Uncertainty Analysis, as the National Academy of Sciences has recommended, would advance this effort.

Once NAAQS have been promulgated, rules established by EPA play a vital role in their implementation. UARG recommends revision of certain aspects of recently-promulgated NAAQS implementation rules, including EPA's March 2015 rule establishing SIP requirements for the 2008 ozone NAAQS[58] and its August 2016 rule establishing SIP requirements for the 2012 $PM_{2.5}$ NAAQS,[59] to eliminate unnecessary and duplicative requirements. Specifically,

---

[57] Memorandum from Marcus Peacock, Deputy Adm'r, EPA, to Dr. George Gray, Assistant Adm'r, Office of Research & Development, & William L. Wehrum, Acting Assistant Adm'r, Office of Air & Radiation (Apr. 17, 2007), https://www3.epa.gov/ttn/naaqs/pdfs/memo_process_for_reviewing_naaqs.pdf.

[58] 80 Fed. Reg. 12,264 (Mar. 6, 2015).

[59] 81 Fed. Reg. 58,010 (Aug. 24, 2016).

UARG urges EPA to revoke the requirement for "anti-backsliding" measures for the 1997 ozone NAAQS,[60] which was replaced in 2008 by a more stringent standard for ozone.[61] Section 172(e) of the CAA requires such measures only when a NAAQS is "relaxed." In addition, UARG recommends that EPA revise its implementation rule for the 2012 $PM_{2.5}$ NAAQS to revoke the less stringent 1997 standard throughout the nation, not just in areas designated attainment.[62] Although UARG recognizes the need for continuity in the NAAQS program and therefore is not recommending that a superseded NAAQS be rendered null immediately upon promulgation of a revised one, UARG recommends that EPA revoke any superseded NAAQS a year after the effective date of area designations for the new or revised NAAQS. The revocation should be effective nationwide. States should not be required to complete an attainment demonstration (or equivalent) for the superseded NAAQS.[63]

Finally, UARG urges EPA to return to its prior approach of relying on air quality monitoring to make initial designations for areas as attainment, nonattainment, or unclassifiable. The SO_2 NAAQS promulgated in 2010 was the first NAAQS for which the Agency chose to rely on modeling predictions—rather than monitoring data—for making initial designations. Modeling is not as accurate as monitoring. EPA's preferred air quality models and required approaches to modeling are conservative by design to ensure that pollutant concentrations in ambient air are not underestimated. EPA acknowledges that its preferred AERMOD model cannot predict pollutant concentrations accurately at a given time and place. Furthermore, EPA continues to revise its AERMOD modeling system, leading to questions concerning the modeling on which designations will be based.[64]

In addition to returning to its prior approach of relying on monitoring for initial designations in the future, EPA should revise nonattainment designations that have already been

---

[60] 40 C.F.R. § 51.1105.

[61] *Compare* 40 C.F.R. § 50.10, *with id.* § 50.15.

[62] *See* 81 Fed. Reg. at 58,142.

[63] *See* Comments by UARG and the American Petroleum Institute on Proposed PM NAAQS Implementation Rule at 61-64 (May 29, 2015), EPA-HQ-OAR-2013-0691-0096; *see also* UARG Comments on Proposed Implementation Rule for the 2015 Ozone NAAQS at 5-8 (Feb. 13, 2017), EPA-HQ-OAR-2016-0202-0105.

[64] *See* Memorandum from Richard A. Wayland, Div. Dir., Air Quality Assessment Div., EPA Office of Air Quality Planning & Standards, to Regional Air Dirs., Regions 1-10 (Mar. 8, 2017) (clarification of the version of the AERMOD modeling system to be used for designations in light of recent revisions of the model), https://www3.epa.gov/ttn/scram/guidance/clarification/SO2_DRR_Designation_Modeling_Clarificaiton_Memo-03082017.pdf.

made based on modeling. Several areas were designated nonattainment based on modeling in 2016,[65] and states have submitted modeling for several other areas for which designations are required by the end of 2017.[66] EPA should use its correction authority under section 110(k)(6) of the Act to replace modeling-based nonattainment designations made in 2016 with unclassifiable designations. Because of the overestimates inherent in modeled air quality, however, attainment designations based on modeling remain valid and should be retained. Furthermore, areas for which designations must be made at the end of 2017 that have not demonstrated attainment through modeling and that do not have adequate monitoring data should be designated unclassifiable; those with adequate monitoring data should be designated according to those data. EPA should also repeal its 2015 Data Requirements Rule for SO_2.[67] That rule places additional burdens on states either to perform modeling or to conduct additional air quality monitoring of SO_2 sources for designations. Although this rule requires the use of either modeling or monitoring, even the monitoring requirement exceeds what is required of states for other criteria air pollutants.[68]

VIII. Air Quality Modeling Issues

On January 17, 2017, EPA promulgated revisions to its Guideline on Air Quality Models, codified at 40 C.F.R. Part 51, Appendix W ("Appendix W").[69] This rule, which specifies models, inputs, and techniques for use in preparing SIPs and PSD permit applications, is not yet effective. Although UARG supports some aspects of the rule revisions, others are expected to make SIP preparation and obtaining permits for new or modified sources more time-consuming and costly. Specifically, UARG is concerned about new modeling requirements for sources seeking permits that emit precursors to ozone or $PM_{2.5.}$ Many electric generators fall in this category. The screening tools that EPA suggests—Significant Impact Levels and Modeled Emission Rates for Precursors—are not particularly helpful in their present form.[70] The photochemical grid modeling mandated for sources not helped by these tools is time-consuming

[65] 81 Fed. Reg. 45,039 (July 12, 2016); 81 Fed. Reg. 89,870 (Dec. 13, 2016).

[66] *See* Fact Sheet: Final Data Requirements Rule for the 2010 1-Hour SO_2 Primary NAAQS (undated), https://www.epa.gov/sites/production/files/2017-02/documents/fact_sheet_-_final_data_requirements_rule.pdf.

[67] 80 Fed. Reg. 51,052 (Aug. 21, 2015).

[68] *See* UARG Comments on the Proposed Data Requirements Rule for the 1-Hour SO_2 NAAQS (July 14, 2014), EPA-HQ-OAR-2013-0711-0075.

[69] 82 Fed. Reg. 5182 (Jan. 17, 2017).

[70] UARG Comments on Draft Guidance on Development of MERPs (Mar. 31, 2017) (attached as Exhibit 2); UARG Comments on Draft Guidance on SILs for Ozone and Fine Particles (Sept. 30, 2016) (attached as Exhibit 3).

and costly. EPA does not specify a particular model to be used, meaning the selected model must be approved on a case-by-case basis. Formal new requirements for written approval by EPA's (non-statutory) Model Clearinghouse whenever a model not specified in Appendix W is used are likely to further delay the process. Accordingly, the NAAQS Implementation Coalition, of which UARG is a member, filed a petition for reconsideration of these and other aspects of the Appendix W revisions.[71]

IX. Demonstration-of-Compliance Issues

A. Outreach on Current Rulemakings

Measures used to demonstrate compliance with emission standards and other requirements, while critical to the effectiveness of a rule, also can significantly increase the rule's cost, particularly if the rule is unclear or contains errors. EPA often initiates rulemakings with the goal of fixing such problems it has identified in rules, but does so without soliciting input from stakeholders on additional ways the rule could be improved. When UARG participates in such proceedings UARG often includes in comments suggestions for other revisions it believes would make the rule more cost effective without sacrificing environmental benefits. Unfortunately, these comments often are rejected as beyond the scope of the rulemaking because they suggest changes the Agency did not propose. To avoid this problem, before engaging in such rulemakings, EPA should solicit input from stakeholders either informally or formally on ways the rule could be made more cost-effective so that the Agency can address those suggestions in its development of the proposal and/or final rule. While some of these suggestions may not by themselves warrant initiating a rulemaking, once EPA decides to initiate a rulemaking it should make a greater effort to ensure that all potential improvements can be achieved.

For example, EPA already has on its regulatory agenda plans to revise the rules governing compliance demonstrations under the Acid Rain Program, and CSAPR at 40 C.F.R. Part 75. UARG believes there are many opportunities to relieve regulatory burdens under those rules by, for example, updating fuel sampling and analysis requirements to reflect current market and operating conditions and incorporating relief already provided for individual sources by petition. EPA should engage in outreach to affected sources prior to issuing its proposal to maximize the improvements to the rule.

---

[71] Petition of the NAAQS Implementation Coalition for Reconsideration of Portions of the Final Rule on Revisions to the Guideline on Air Quality Models (Mar. 20, 2017), EPA-HQ-OAR-2015-0310-0181.

B. The So-Called "Credible Evidence Rule"

In 1997, EPA promulgated revisions to 40 C.F.R. Parts 51, 52, 60, and 61 removing restrictions on the use of information other than the EPA or state-specified compliance method to establish violations of, or compliance with, emission limitations.[72] Later, EPA revised its model rules for Federal Permit Operating Programs under Title V at 40 C.F.R. Parts 70 and 71 to require identification and consideration of information other than the specified compliance method when certifying compliance with permit terms and conditions.[73] These rules, which have so far avoided judicial review,[74] impose significant regulatory burdens and uncertainty on sources regarding the standard for compliance and responsible officials' obligations when making certifications or compliance under penalty of perjury. They also are inconsistent with Congress' limited authorization to use such information when assessing civil penalties only to determine the duration of a violation that already has been established using the specified compliance method. EPA should engage in rulemaking to repeal or revise these rules to limit the methods for establishing violations and determining compliance to those specified in rules and permits, and to limit use of other information to establishing the duration of a violation or compliance, consistent with Congress' direction in CAA § 113(e).

* * * * * * * *

UARG appreciates this opportunity to provide input on EPA regulations that may be appropriate for repeal, replacement, or modification. We look forward to the future opportunities for engagement mentioned in the *Federal Register* notice. Please feel free to contact me with any questions.

Sincerely,

/s/ Andrea B. Field
Andrea Field
Counsel for the Utility Air Regulatory Group

---

[72] 62 Fed. Reg. 8314 (Feb. 24, 1997).

[73] 62 Fed. Reg. 54,900, 54,946-47 (Oct. 22, 1997); 79 Fed. Reg. 43,661 (Jul. 28, 2014).

[74] Industry groups, including UARG, challenged both rules when they were promulgated, but the U.S. Court of Appeals for the D.C. Circuit refused to review their validity, finding instead that the challenges were not "ripe for review." *Clean Air Implementation Project v. EPA*, 150 F.3d 1200 (D.C. Cir. 1998); *NRDC v. EPA*, 194 F.3d 130 (D.C. Cir. 1999).

EXHIBIT 1

BEFORE THE ADMINISTRATOR OF THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Protection of Visibility: Amendments to Requirements for State Plans; Final Rule. 82 Fed. Reg. 3078 (Jan. 10, 2017)	Docket No. EPA-HQ-OAR-2015-0531

PETITION OF THE UTILITY AIR REGULATORY GROUP TO THE ADMINISTRATOR OF THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY FOR PARTIAL ADMINISTRATIVE RECONSIDERATION OF THE FINAL RULE

Norman W. Fichthorn
Aaron M. Flynn
HUNTON & WILLIAMS LLP
2200 Pennsylvania Avenue, N.W.
Washington, DC 20037
(202) 955-1500

Counsel for the
Utility Air Regulatory Group

Dated: March 13, 2017

PETITION OF THE UTILITY AIR REGULATORY GROUP TO THE ADMINISTRATOR OF THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY FOR PARTIAL ADMINISTRATIVE RECONSIDERATION OF THE FINAL RULE

Pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act ("CAA" or "Act"), 42 U.S.C. § 7607(d)(7)(B), the Utility Air Regulatory Group ("UARG")[1] hereby respectfully petitions the Administrator of the United States Environmental Protection Agency ("EPA" or "Agency") to reconsider certain provisions of the final rule entitled "Protection of Visibility: Amendments to Requirements for State Plans" (hereinafter "Rule"), published at 82 Fed. Reg. 3078 (Jan. 10, 2017), which Administrator Gina McCarthy made effective immediately upon the Rule's publication in the Federal Register, thereby evading normal review by the current Administration. Specifically, UARG requests that EPA reconsider provisions of the Rule that address certain aspects of:

- EPA's views on the CAA's requirements for cooperative federalism and states' prerogatives in developing, and receiving EPA approval of, their implementation plans under the Act;
- The relationship between long-term strategies ("LTSs") and reasonable progress goals ("RPGs") and visibility-improvement state implementation plans ("SIPs");
- States' LTS obligations;
- Modifications to methods for determining the set of days used to track progress toward natural visibility conditions to account for natural visibility-impairing events such as wildfires and dust storms;
- States' authority and discretion to account for effects on visibility from anthropogenic emission sources located outside the United States and from prescribed fires;
- Modifications related to the timing and form of regional haze progress reports; and
- Revisions to the "reasonably attributable visibility impairment" ("RAVI") provisions of the Regional Haze Rules ("RHR").

In addition, the preamble to the Rule contains statements that do not accurately reflect provisions of the CAA or that otherwise misstate important facts relevant to implementation of

[1] UARG is a not-for-profit association of individual electric generating companies and national trade associations. The vast majority of electric energy in the United States is generated by individual members of UARG or other members of UARG's trade association members. UARG participates on behalf of certain of its members collectively in CAA administrative proceedings that affect electric generators and in litigation arising from those proceedings.

the Act's visibility protection program. UARG respectfully requests that EPA, on reconsideration, correct and clarify these misstatements.

The Rule also effects a one-time adjustment of the due date for the next periodic regional haze SIP revisions by extending the previous deadline of July 31, 2018, by three years, to July 31, 2021. EPA provided a thorough and reasonable justification for that modification, *see* 82 Fed. Reg. at 3080, 3116-18, which UARG believes is both warranted and highly beneficial, for the reasons EPA gave.[2] Moreover, EPA has full legal authority to make this adjustment; nothing in the CAA limits EPA's ability to extend this SIP submittal date. Accordingly, UARG does ***not*** seek reconsideration of this element of the Rule, which EPA should retain.

Reconsideration of certain other specific aspects of the Rule, as discussed below, is especially warranted due to the highly unusual procedural posture of the Rule. Unlike every other significant, nationally applicable CAA visibility-program rule of which UARG is aware—including rules promulgated by EPA under administrations of both political parties—this Rule, as published in the Federal Register, was, uniquely, given an *immediate effective date of January 10, 2017*, the same date it was published in the Federal Register. *Cf.* 71 Fed. Reg. 60,612 (Oct. 13, 2006) (60-day effective date after Federal Register publication date); 70 Fed. Reg. 39,104 (July 6, 2005) (same); 64 Fed. Reg. 35,714 (July 1, 1999) (same); 45 Fed. Reg. 80,084 (Dec. 2, 1980) (30-day effective date after Federal Register publication date). This historically unprecedented immediate effective date is a clear change from the as-signed version of the Rule, which former Administrator McCarthy signed on December 14, 2016, and which provided that the Rule would become effective *30 days after the date of its publication in the Federal Register*. *See* Attachment 1 hereto, page 2. That is the usual course of action for significant EPA rules under the CAA like the rule at issue here.

Yet in the final rule as published in the Federal Register on January 10, 2017, former Administrator McCarthy—without even acknowledging the effective-date alteration from the final rule that she signed[3]—purported to make the Rule effective immediately upon publication. The former Administrator also added new language to the published version of the Rule—language that did not appear in the rule she signed—purporting to justify EPA's novel decision to establish an immediate effective date. The preamble of the published Rule observes that the APA authorizes "an effective date less than 30 days after publication for a rule that 'grants or recognizes an exemption or relieves a restriction.'" 82 Fed. Reg. at 3079. Administrator

[2] In addition, the substantial regulatory revisions made by the Rule raise a wide range of questions and create uncertainties that states will need considerable additional time to address and resolve as they prepare SIPs for the second regional haze planning period. Further potential changes to the Rule, resulting from this petition for reconsideration or from petitions for review of the Rule that have been filed in the U.S. Court of Appeals for the D.C. Circuit, *State of Texas, et al. v. EPA*, No. 17-1021 (D.C. Cir.), are additional factors supporting EPA's rulemaking determination to give states more time to develop and submit regional haze SIPs for the second planning period.

[3] That omission itself was misleading to members of the public, who may generally have been unaware that the rule as signed provided for an effective date 30 days after the rule's publication in the Federal Register.

McCarthy further stated that the three-year SIP-deadline extension—from July 2018 to July 2021—that is provided by the Rule "is comparable to the grant of an exemption or relief from a restriction because it provides more time for states to meet a regulatory requirement" and, for that reason, EPA asserted that it believed it was reasonable to establish an immediate effective date. *Id.*

This putative rationale was, however, disingenuous. The reason for an immediate effective date when rules grant exemptions or relieve restrictions is to make the exemption or relief immediately available, where appropriate. Here, the relief provided by the Rule would not have been affected in the least by retaining the 30-day effective date that the as-signed Rule established because, in the absence of the Rule's SIP-submittal deadline extension, the SIP-submittal deadline still would not occur until July 31, 2018, *more than a year and a half* after the Rule's publication date. Moreover, EPA did not even attempt to offer an explanation as to why the remainder of the Rule required or warranted an immediate effective date.

In fact, it is obvious that the real reason for the unacknowledged effective-date alteration was to circumvent the normal and proper regulatory review process that was initiated at the beginning of the current Administration (and that is still under way), a process that has been much the same as the review process that occurred at the beginning of the two preceding administrations (including the administration in which Administrator McCarthy served). By the time the Rule was ready to be published in the Federal Register, it was clear it would not be published more than 30 days before the President's inauguration—and thus, in the normal course, would have become subject to a regulatory freeze similar to those established by previous incoming administrations and similar to the freeze that in fact the current Administration put in place on January 20, 2017.[4] Moreover, all of the purported justifications that EPA stated in the preamble to the January 10, 2017 as-published Rule for making the Rule immediately effective were not any less applicable to the as-signed December 14 final rule than they were to the Rule as published. Thus, the only plausible reason for the effective-date change in the published Rule was to evade the current Administration's normal regulatory review.

Accordingly, in light of this highly irregular effective-date alteration designed to circumvent the normal administrative review process to which other EPA regulatory actions issued under the previous administration were (and are) subject, UARG respectfully submits that it is especially important for EPA to grant this petition to allow thorough review of the Rule

[4] *See* Memorandum from Reince Priebus, Assistant to the President and Chief of Staff, to the Heads of Executive Departments and Agencies, "Regulatory Freeze Pending Review" (Jan. 20, 2017), *published in* 82 Fed. Reg. 8346 (Jan. 24, 2017); *see also* EPA Final Rule, Delay of Effective Date for 30 Final Regulations Published by the Environmental Protection Agency Between October 28, 2016 and January 17, 2017, 82 Fed. Reg. 8499, 8500-01 (Jan. 26, 2017) (including a list of EPA rules whose effective dates did not occur by January 20, 2017, and whose effectiveness was therefore deferred until at least March 21, 2017).

and to reconsider and revise, as appropriate, pertinent provisions of the Rule as described in this petition.[5]

I. Cooperative Federalism

The Rule's preamble discusses cooperative federalism and EPA's role in relation to the states in implementing the visibility program. *Id.* at 3090. In that discussion, EPA asserts that the holding of the U.S. Court of Appeals for the Fifth Circuit that EPA's role in reviewing regional haze SIPs is "ministerial," *Texas v. EPA*, 829 F.3d 405, 411, 428 (5th Cir. 2016), is erroneous, and EPA further suggests that the D.C. Circuit's decision in *American Corn Growers Association v. EPA*, 291 F.3d 1 (D.C. Cir. 2002) ("*Corn Growers*"), does not require EPA deference to state policy decisions. That preamble discussion is incorrect.

The CAA, the 1999 RHR, the 2005 and 2006 revisions to those rules, EPA's BART Guidelines, and the D.C. Circuit's decision in *Corn Growers* all emphasize state primacy in implementing the regional haze program. Contrary to these legally binding authorities, however, EPA has often failed, during the past eight years, to adhere to the state primacy principle when it has reviewed regional haze SIPs. EPA instead often invoked a vague "reasonableness" standard that it used to second-guess state policy decisions and to substitute EPA's own policy choices. EPA frequently did this by resorting to narrow readings of the RHR and the BART Guidelines. For instance, it repeatedly insisted on state adherence to EPA's Control Cost Manual ("Manual") even though the Manual is not a rule and the RHR and Guidelines properly make clear that the Manual is simply one option for states to use when they evaluate costs of emission controls. EPA also repeatedly insisted on its preferred approach to assessing visibility impacts, favoring a cumulative deciview ("dv") assessment. By improperly claiming that these and other analytical methods are regulatory requirements and not merely options for states to consider, EPA has determined that numerous regional haze SIPs are, in its view, "unreasonable" and, on that basis, disapproved them, replacing what in fact were reasonable and lawful state determinations with more costly emission control requirements in EPA-imposed federal implementation plans ("FIPs").

EPA now has an opportunity to correct its recent misuse of the regional haze program. On reconsideration, the Agency should revise the Rule to clearly emphasize state decision-making authority and to remove language that EPA has improperly used to limit state discretion.

II. The Relationship Between RPGs and a State's LTS

The Rule includes what EPA terms a "clarification" of the relationship between RPGs and a state's LTS. 82 Fed. Reg. at 3090-96. Under EPA's interpretation, states *must first* determine the measures to be included in an LTS based on an assessment of the reasonable progress factors and *only then* calculate the RPGs that would result from implementing those measures. EPA claims this is its longstanding position and that this position is consistent with its 2007 "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program" ("2007 Guidance"). *Id.* at 3092. That is not the case. As UARG explained in its comments on

[5] UARG may supplement this petition for partial administrative reconsideration in the future based on further review of information in EPA's regulatory docket or otherwise.

the proposed version of the Rule,[6] this position was formulated and stated for the first time in EPA's January 5, 2016 regional haze rule for Texas and Oklahoma. 79 Fed. Reg. 74,818 (Dec. 16, 2014) (proposed rule); 81 Fed. Reg. 296 (Jan. 5, 2016) (final rule). EPA's position, in fact, contradicts the 2007 Guidance, as the attached UARG Comments discuss.

EPA's position as stated in the Rule's preamble is also inconsistent with the D.C. Circuit's decision in *Corn Growers*. The D.C. Circuit explained that EPA's 1999 RHR provides that "the determination of what specific control measures must be implemented 'can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress.'" *Corn Growers*, 291 F.3d at 4 (quoting 64 Fed. Reg. at 35,721 (July 1, 1999)). In fact, EPA's position as stated in the Rule's preamble is inconsistent even with its own articulation of the relationship between RPGs and LTSs as recently as March 2, 2017, when EPA published a proposed rule to address interstate visibility transport SIP requirements for Tennessee. In that proposed rule, which was signed on February 21, 2017, EPA referred to states' reliance on emission limitation measures "as . . . element[s] of a long-term strategy for achieving their reasonable progress goals" and noted that *the LTS is to be designed to be "sufficient to achieve the state-adopted reasonable progress goals*." 82 Fed. Reg. 12,328, 12,332 (Mar. 2, 2017) (emphasis added). In other words, properly understood, the existing rules have long called on—or, at the very least, permitted—states to set RPGs first and *then* to develop LTSs that are "sufficient to achieve" the RPGs, as reflected in these EPA statements in this March 2, 2017 proposed rule.

As a result, the Rule's purported clarification of the relationship between RPGs and LTSs is actually a revisionist reinterpretation of existing, long-standing regulatory provisions and should be disavowed and rescinded by EPA on reconsideration. In any revised (or other future) rule, EPA should eschew imposition of any unnecessary and improper constraint on how states undertake these SIP determinations.

III. Additional LTS Obligations that the Rule Imposes on States

The Rule makes other revisions to the LTS requirements. As explained below, many of these should be changed on reconsideration.

For instance, the Rule's preamble counterintuitively states that SIPs that ensure reasonable progress consistent with the uniform rate of progress ("URP")—*i.e.*, the rate of progress that, if steadily maintained, will achieve natural visibility conditions by 2064—nonetheless may not be designed to achieve reasonable progress and will not necessarily receive EPA's approval. 82 Fed. Reg. at 3093, 3099-100. EPA contends in the Rule that consistency with the URP was not intended to provide a regulatory "safe harbor" for states and that states that establish RPGs that meet the URP—and even states that establish RPGs that reflect more

[6] Comments of the Utility Air Regulatory Group on the U.S. Environmental Protection Agency's Proposed Rule, "Protection of Visibility: Amendments to Requirements for State Plans" at 10-11 (Aug. 10, 2016), Docket No. EPA-HQ-OAR-2015-0531-0578 ("UARG Comments"). The UARG Comments are attached hereto as Attachment 2 and incorporated herein by reference insofar as they are germane to the issues that this petition addresses.

accelerated progress than the URP—must nevertheless conduct a full reasonable progress analysis to determine if *even more* progress can be made. *Id.* This is an unreasonable position that, as the UARG Comments demonstrated, is at odds with the 1999 RHR, *see* UARG Comments at 14-16, and should be withdrawn on reconsideration.[7]

Conversely, the Rule provides that if a state's RPG is set above the URP glidepath (*i.e.*, reflects a less expeditious rate of improvement than the URP), the state is *required* to make a "robust" demonstration, based on the reasonable progress factors, that more emission reductions are not reasonable. 82 Fed. Reg. at 3099. There is no statutory or rational basis to include this vague and unnecessarily burdensome additional requirement, which arbitrarily compels states to attempt to prove a negative. If a state has conducted a reasonable progress evaluation and found that a rate of progress less accelerated than the URP is reasonable, then that should be the end of the inquiry. EPA's Rule appears to assume that the result of a state's reasonable progress analysis may be insufficient to achieve reasonable progress. This provision is inconsistent with the CAA, is unsupported by any evidence presented in the Rule, and should be withdrawn on reconsideration.

EPA also included rule changes to the provision of the RHR addressing documentation requirements. *Id.* at 3096. The Rule makes it an explicit requirement that states provide documentation related to "modeling, monitoring, cost, engineering, and emissions information[] on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects." *Id.* Over the last eight years, EPA has used a purported lack of adequate state documentation as a basis on which to disapprove SIPs, even when states provided detailed information to EPA in support of their SIPs. On reconsideration, EPA should make clear that states have significant and broad discretion in this area.

IV. Selection of Days Used To Track Progress To Account for Events Such as Wildfires

The Rule properly acknowledges that natural events such as wildland wildfires can have significant visibility effects and can overwhelm visibility improvements that are attributable to reductions in emissions from anthropogenic sources. *See generally id.* at 3101-03. The Rule revises the RHR to direct states to exclude visibility impairment attributable to non-anthropogenic sources from consideration in the CAA's visibility program, such that reasonable progress will be assessed based on the 20 percent most impaired days based on anthropogenic impairment, rather than based on the highest dv values due to all sources affecting visibility. EPA declined, however, to allow states to choose to base SIPs on an assessment of reasonable progress that addresses the overall haziest days. *Id.* at 3102. EPA should revise the Rule on reconsideration to allow an individual state to decide which approach it wants to adopt.

[7] In the Rule, EPA claims that reliance on consistency with the URP in place of conducting a four-factor analysis would be at odds with the CAA, 82 Fed. Reg. at 3099, but that view fails to recognize that states can reasonably determine that meeting the URP is consistent with results of a four-factor assessment.

The Rule also notes that EPA developed draft guidance, which EPA has not finalized,[8] that offers a specific methodology for determining "natural versus anthropogenic contributions to daily haze," but it also recognizes that states are not bound to that methodology and that states are free to "develop, justify and use another method of discerning natural and anthropogenic contributions to visibility impairment in their SIPs." *Id*. at 3103. On reconsideration, EPA should make clear that states have broad leeway in developing these methods and that a state's decision to use a method other than the method provided for in any EPA guidance document is not a basis for disapproving a regional haze SIP.

V. Authority To Account for Effects on Visibility from Anthropogenic Sources Located Outside the United States and from Certain Types of Prescribed Fires

The Rule's preamble properly explains that visibility impairment resulting from anthropogenic emissions from non-U.S. sources need not be addressed through the regional haze program and that states should be able to account for such emissions when they develop their regional haze SIPs. *Id*. at 3104. To that end, EPA in the Rule revised the RHR to allow states to remove the effects of non-U.S. emissions from their estimates of natural visibility conditions when they calculate URPs. Although this provision is itself reasonable, problems arise from the Rule's treatment of non-U.S. anthropogenic emissions, and EPA should address such problems on reconsideration.

First, EPA solicited comment on a possible approach that would allow states to remove non-U.S. anthropogenic emissions not only from the estimate of natural visibility conditions for purposes of calculating the URP but also from the estimates of 2000–2004 baseline visibility conditions, current visibility conditions, and the RPGs. 81 Fed. Reg. 26,942, 26,956 n.29 (May 4, 2016). EPA says it decided against finalizing this aspect of the proposed rule "to provide consistency and transparency." 82 Fed. Reg. at 3105. This vague assertion is not an adequate reason to deny states the discretion to decide how best to account for non-U.S. emissions. On reconsideration, EPA should revise the Rule to allow states this option.

The Rule also fails to address a significant shortcoming in EPA's proposed rule: states' lack—as EPA characterized it—of tools and data necessary to account adequately for non-U.S. anthropogenic emissions. EPA in the Rule suggests that such emissions cannot be accounted for with "sufficient accuracy," *id.* at 3104, and EPA declined to provide states with what it deemed acceptable emission estimates and declined to agree to defer to state decision-making on this issue. On reconsideration, EPA should offer states the option of using a sound, workable approach to account for non-U.S. emissions. Even more important, EPA should make a firm commitment to accept state determinations on how to account for the effects of such emissions.

The Rule also properly includes a provision allowing states to account for wildland prescribed fires "conducted for purposes of ecosystem health and public safety during which

[8] If EPA grants partial reconsideration of the Rule as UARG requests herein, EPA will also need to revise the draft guidance document to conform it to any revised version of the Rule that EPA ultimately promulgates. In any event, UARG urges EPA not to take any action to make the draft guidance final pending the Agency's review and action on this petition for partial reconsideration.

appropriate basic smoke management practices have been applied" by removing the influence of such events from the URP. *Id.* at 3107. The Rule, however, provides no valid basis for distinguishing in this respect between wildland prescribed fires and other types of prescribed fires, including prescribed fires on commercial and private lands. The same land and resource management considerations that EPA describes with respect to wildland management apply with equal force to other categories of lands, and there is no reason to require other sources of visibility-impairing emissions to make up for emissions that result from any category of prescribed fires. On reconsideration, EPA should expand this provision to encompass all kinds of prescribed fires and to allow states to treat emissions from such fires in the same way as emissions from wildland wildfires.

VI. Timing and Form of Progress Reports

EPA also should reconsider the Rule's revisions governing states' regional haze progress reports. In the Rule, EPA purports to relieve states' administrative burdens by changing the required form of these reports so that states no longer must submit them as SIP revisions, but EPA retains two of the most significant and burdensome aspects of the SIP-revision process—the public notice requirement and the requirement to consult with federal land managers ("FLMs")—thereby, in effect, eliminating little more than *EPA*'s own administrative burden to review and act on progress report SIPs submitted by states. *Id.* at 3119-20.

Instead, EPA on reconsideration should eliminate the requirement for progress reports altogether. *See* UARG Comments at 32-33. Nothing in section 169A or section 169B of the Act, 42 U.S.C. §§ 7491, 7492, requires interim progress reports, and EPA in the Rule does not identify any statutory basis for them. EPA also does not show that they have been demonstrated to have significant usefulness. The requirement that states prepare and submit substantive regional haze SIP revisions periodically for each implementation period is adequate to ensure reasonable progress. A given state would of course be free to choose to prepare and submit to EPA (or simply to make available to the public) an interim progress report, but no state should be obligated to do so by EPA's rules.

VII. Revisions to RAVI Provisions

The Rule revises elements of the RAVI program largely as EPA had proposed. With respect to the Rule's RAVI revisions, UARG agrees that, if the RAVI program is retained at all, it was proper for EPA to eliminate the recurring obligation that states periodically review their RAVI SIPs and to require instead that states undertake such reviews only if an FLM has made a RAVI certification. *Id.* at 3112-15.

The Rule's other revisions to the RAVI program are more problematic. As UARG explained in its comments on the proposed version of the rule, *see* UARG Comments at 22-31, EPA revised the RAVI provisions to expand unlawfully FLMs' role and included rule amendments that could give rise to interpretations that would limit state discretion, such as the change to the RHR definition of "reasonably attributable."

These problems could be avoided by terminating the RAVI program, and there are good reasons for doing so on reconsideration of the Rule. As EPA's own recounting of the history of the RAVI program makes clear, the program has rarely been used and is unnecessary to achieve the CAA objective of eliminating and remedying anthropogenic air pollution that contributes to visibility impairment. *See* 82 Fed. Reg. at 3081-82. That objective can be met through implementation of the regional haze program alone. Indeed, by revising the RHR to suggest that FLMs may make RAVI certifications based on modeling, the Rule blurs the lines between the regional haze program and RAVI, which was intended to address "plume blight" attributable to a single source or a small group of sources, and not other forms of visibility impairment. For these reasons, EPA on reconsideration should adopt a rule change that sunsets the RAVI program.

For similar reasons, EPA should rescind its rule provisions pertaining to "integral vistas." EPA had proposed to do that but announced in the preamble to the Rule that

> because the definition in 40 CFR 51.301 that "visibility in any mandatory Class I Federal area includes any integral vista associated with that area" and because there are several provisions that after our final action continue to use the term "visibility in any mandatory Class I Federal area," there are some provisions where the existence of a single identified integral vista could conceivably make a difference to the obligation of some party or to an EPA action.

Id. at 3115 (emphasis omitted). This is an inadequate justification for retaining the obsolete and unused integral vistas provisions. The provisions are outdated, can give rise to regulatory confusion, and should be eliminated, including the reference in the 40 C.F.R. § 51.301 definition that EPA cites as the justification for retaining the integral vistas provisions.

VIII. FLM Consultation

The Rule makes final EPA's proposed requirement that states begin consultation with FLMs "early enough" so that FLM recommendations "can meaningfully inform the State's decisions." *Id*. at 3128. Under the Rule, consultation will be deemed to have begun "early enough" if it occurs at least 120 days before the state holds any public hearing (or 120 days before some other public comment opportunity) on a revised regional haze SIP, but consultation must in any event occur no later than 60 days before that hearing or other public comment opportunity. *Id*. UARG in its comments argued that the existing rule requirement to consult at least 60 days before a hearing was adequate and consistent with the CAA. UARG Comments at 31-32. The Rule's revisions on this issue add unnecessary uncertainty and confusion to a process that previously was comparatively well-defined. In practice, states may conclude that they will need to initiate consultation 120 days (or more) before the hearing or public comment opportunity in order to avoid questions about whether consultation occurred "early enough." Such a confusing and potentially demanding consultation requirement is in conflict with the CAA, which simply requires consultation by states with FLMs "[b]efore holding the public hearing." CAA § 169A(d), 42 U.S.C. § 7491(d); *see* UARG Comments at 31-32. On reconsideration, the Rule's revision on this issue should be rescinded.

IX. On Reconsideration, EPA Should Correct Additional Errors, Misstatements, and Other Points in the Rule's Preamble.

The Rule is replete with additional errors and misstatements—most likely evidence, at least in some instances, of undue haste as EPA rushed to complete the rulemaking before the end of the previous administration[9]—a fact that also warrants a grant of reconsideration.[10] Moreover, EPA on reconsideration should take the opportunity to clarify certain points addressed in the Rule's preamble, as discussed below.

For instance, with respect to errors, EPA says in the preamble: "The 1999 RHR then provided that these three states [New Mexico, Utah, and Wyoming] will revert to the progress report requirements in 40 CFR 51.308 after the report currently due in 2018. We did not propose this aspect of the RHR." 82 Fed. Reg. at 3086. It seems likely that EPA intended to state that it did not propose to *alter* this aspect of the RHR, but EPA's precise intention cannot be discerned from this passage in the preamble. Granting reconsideration would allow EPA to correct this and any related errors in the Rule.

In addition, the Rule's preamble appears to contain significant errors at 82 Fed. Reg. at 3100, which repeatedly refers to a specific quoted phrase—"emissions information on which the State's strategies are based"—that, according to the preamble, is a key term of art in the Rule and that supposedly appears in the regulatory text at 40 C.F.R. § 51.308(f)(2)(iv). But that phrase does not appear in the cited regulatory provision or, as far as UARG has been able to determine, in any other provision of the Rule.

Similarly, the preamble states that the Rule "finaliz[es] 40 CFR 51.308(f)(3)(ii)" to allow for adjustments to the URP to address effects of certain wildland fires. 82 Fed. Reg. at 3109. In fact, however, nothing on the face of that provision addresses effects of wildland fires at all.

Many other errors appear throughout the preamble, potentially leading to further confusion and uncertainty as to the intent and effect of various aspects of the Rule and providing further evidence of a rush to complete the rule in time to avoid the normal regulatory review process at the beginning of an administration. For example, a sentence appearing at 82 Fed. Reg. at 3095—in the section of the preamble in which EPA purports to "clarify" its supposedly "[l]ong-[s]tanding [i]nterpretation" of the relationship between LTSs and RPGs (82 Fed. Reg. at 3090)—is far from clarifying; indeed, it is incomprehensible, stating in its entirety that:

---

[9] For the reasons noted above, EPA presumably sought (but failed) to complete and sign the Rule in time to allow its publication in the Federal Register more than 30 days before January 20, 2017.

[10] UARG emphasizes that the errors and misstatements in the Rule described in this petition do not necessarily constitute an exhaustive list of errors and misstatements in the Rule. UARG may supplement this petition to describe additional errors and misstatements that may exist in the Rule and its preamble, as published in the Federal Register, or in other relevant EPA documents in the rulemaking docket.

> Under this provision, states must consider whether the emission reduction measures other states have identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area. [sic]

See also, e.g., id. at 3088 ("To the extent that one state does not provide another other state [sic] with these analyses and information, ..."); *id.* at 3093 (" . . . some of lesser set of measures [sic] . . ."); *id.* at 3094 (" . . . would affect [sic] a substantive change . . ."); *id.* at 3095 (" . . . to affect [sic] a substantive change . . ."); *id.* at 3097 (" . . . the URP at each Class I areas [sic] . . . "); *id.* at 3102 (" . . . the statistical summaries of these days need [sic] as part of a SIP revision . . .").

With respect to additional factual misstatements, the Rule's preamble also repeats a statement EPA has often made: that "[m]ost people can detect a change in visibility of one deciview." *Id*. at 3083. The best available evidence establishes that a more significant change is generally required before the human eye can detect a change in visibility conditions. *See, e.g.*, 70 Fed. Reg. at 39,129 & nn.50 & 51 (July 6, 2005); Pitchford, M., and Malm, W., "Development and Applications of a Standard Visual Index," *Atmospheric Environment*, Vol. 28, pp. 1049-54 (1994) (finding that a change of approximately 1 to 2 dv is necessary for human perception); Henry, R. C., "Just-Noticeable Differences in Atmospheric Haze," *Journal of the Air & Waste Management Association*, Vol. 52, pp. 1238-43 (2002) (finding that a change of at least 1.8 dv is necessary for human perception). EPA should revisit this conclusion on reconsideration and revise the Rule's statement on this important issue accordingly to more accurately and carefully reflect the available scientific evidence.

The preamble to the Rule also notes that "[t]he 1999 RHR defined 'visibility impairment' as a humanly perceptible change (*i.e.*, difference) in visibility from that which would have existed under natural conditions." 82 Fed. Reg. at 3083. In numerous proceedings, however, EPA previously has denied that human perceptibility is a consideration that states can properly take into account in developing regional haze SIPs, and EPA appears to have taken the position that it is unimportant to the regional haze program overall. On reconsideration, EPA should revise the Rule to clarify that human perceptibility of visibility changes is plainly a proper factor for states to consider when they determine whether and to what extent particular emission controls are justified.

The Rule's preamble also states that sources that installed BART during the regional haze program's first implementation period "may need to be re-assessed for additional controls in future implementation periods under the CAA's reasonable progress provisions." *Id*. Although states may choose to reassess subject-to-BART sources, EPA on reconsideration should make clear that they have no legal obligation to do so.

In addition, the preamble to the Rule contains a detailed discussion of the characterization by EPA under the previous administration of the decision of the Fifth Circuit on the stay of EPA's January 2016 regional haze rule for Texas and Oklahoma. *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016). In the preamble, EPA argues that that judicial decision has caused "confusion" about three important topics: (1) whether states must apply the reasonable progress factors on a source-by-source basis; (2) the scope of the interstate consultation requirement; and (3) whether EPA can properly require inclusion of emission control measures in an LTS if those measures cannot be implemented within the current planning period. *Id*. at 3087. EPA properly concedes, as it must, that states cannot be required to conduct source-specific reasonable progress analyses, and EPA acknowledges that states have flexibility in deciding how to conduct such analyses. *Id*. at 3088. Nevertheless, EPA says:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.

Id. In several instances, including EPA's actions on regional haze plans for Texas and Oklahoma, EPA invoked this sort of vague requirement that states "exercise reasoned judgment" to justify EPA's subjective decisions to disapprove SIPs and to promulgate FIPs with more expensive and stringent (but not necessarily soundly supported) requirements. On reconsideration, EPA should correct the above-quoted statement to recognize and clarify the narrowly circumscribed scope of its authority to review and disapprove regional haze SIPs, and to recognize that EPA may not disapprove SIPs on the basis of EPA's own views regarding whether and to what extent the state "exercise[d] reasoned judgment."

EPA in the preamble makes a similar statement regarding the scope of the interstate consultation requirement, asserting that states must share information when developing their RPGs and that

> [t]o the extent that one state does not provide another other [sic] state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements.

Id. Again, the criteria that EPA appears here to have been attempting to construct—*i.e.*, criteria addressing whether the analyses or information that a state shared were "materially deficient" and whether a state "meaningfully compl[ied]"—are far too vague to be workable or appropriate, particularly in light of the high degree of deference that is due to states' determinations. On reconsideration, EPA should make clear that states can decide how to consult with one another and that, absent a genuine, significant, and unresolved dispute between or among states, EPA lacks any valid basis for assessing the reasonableness or completeness of the interstate consultation.

Finally, EPA claims that the Fifth Circuit was incorrect to determine that EPA likely had acted unlawfully by imposing requirements for Texas sources that could not be implemented before the end of the first planning period of the regional haze program. *Id*. at 3088-89. EPA argues that the requirement that states or EPA consider "the time necessary for compliance" when assessing reasonable progress allows EPA to include (or allows EPA to compel states to include) measures in an LTS even if those measures cannot be implemented during the then-current planning period. This is a patently unreasonable interpretation of the CAA and inconsistent with the structure of the program. If the purpose of the measures included in the LTS is to achieve the visibility improvement reflected in an RPG, as EPA has said is the case, and the RPG is tied to the end of each planning period, then the measures required must be capable of being implemented within that planning period. On reconsideration, EPA should revise its interpretation accordingly.

X. Conclusion

Because, as described above, the Rule contains and reflects serious flaws and misguided and unsupported policy decisions, and because of former Administrator McCarthy's highly irregular action to alter the text of the Rule as signed to make it effective immediately—thereby allowing the Rule to evade the customary regulatory review at the outset of a new Administration—UARG respectfully requests that the Administrator promptly grant this request for partial reconsideration and initiate a proceeding to revise the Rule consistent with this petition.

Attachment 1

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA-HQ-OAR-2015-0531; FRL-9957-05-OAR]

RIN 2060-AS55

Protection of Visibility: Amendments to Requirements for State Plans

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions to requirements under the Clean Air Act (CAA) for state plans for protection of visibility in mandatory Class I Federal areas in order to continue steady environmental progress while addressing administrative aspects of the program. In summary, the revisions clarify the relationship between long-term strategies and reasonable progress goals (RPGs) in state implementation plans (SIPs) and the long-term strategy obligation of all states; clarify and modify the requirements for periodic comprehensive revisions of SIPs; modify the set of days used to track progress towards natural visibility conditions to account for events such as wildfires; provide states with additional flexibility to address impacts on visibility from anthropogenic sources outside the United States (U.S.) and from certain types of prescribed fires; modify certain requirements related to the timing and form of progress reports; and update, simplify and extend to all states the provisions for reasonably attributable visibility impairment, while revoking most existing reasonably attributable visibility impairment federal

implementation plans (FIPs). The EPA also is making a one-time adjustment to the due date for the next periodic comprehensive SIP revisions by extending the existing deadline of July 31, 2018, to July 31, 2021.

DATES: This final rule is effective on **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: The EPA established Docket ID No. EPA-HQ-OAR-2015-0531 for this action. All documents in the docket are listed in the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically in *http://www.regulations.gov*.

FOR FURTHER INFORMATION, CONTACT: For general information regarding this rule, contact Mr. Christopher Werner, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541-5133 or by email at *werner.christopher@epa.gov*; or Ms. Rhea Jones, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, by phone at (919) 541-2940 or by email at *jones.rhea@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Preamble Glossary of Terms and Acronyms

The following are abbreviations of terms used in this document.

AQRV	Air quality related value

BART	Best available retrofit technology
b_{ext}	Light extinction
CAA	Clean Air Act
CFR	Code of Federal Regulations
EGU	Electric generating unit
EPA	Environmental Protection Agency
FIP	Federal implementation plan
FLM or FLMs	Federal Land Manager or Managers
ICR	Information collection request
IMPROVE	Interagency monitoring of protected visual environments
NAAQS	National Ambient Air Quality Standards
NSR	New Source Review
NO_x	Nitrogen oxides
OMB	Office of Management and Budget
PM	Particulate matter
$PM_{2.5}$	Particulate matter equal to or less than 2.5 microns in diameter (fine particulate matter)
PM_{10}	Particulate matter equal to or less than 10 microns in diameter
PRA	Paperwork Reduction Act
RHR	Regional Haze Rule
RPG	Reasonable progress goal
RPO	Regional planning organization
SIP	State implementation plan
SO_2	Sulfur dioxide
TAR	Tribal Authority Rule
URP	Uniform rate of progress

B. Entities Affected by This Rule

Entities potentially affected directly by this rule include state, local and tribal[1] governments, as well as FLMs responsible for protection of visibility in mandatory Class I federal areas.[2] Entities potentially affected indirectly by this rule include owners and operators of sources that emit particulate matter equal to or less than 10 microns in diameter (PM_{10}), particulate matter equal to or less than 2.5 microns in diameter ($PM_{2.5}$ or fine PM), sulfur dioxide (SO_2), oxides of nitrogen (NO_x), volatile organic compounds and other pollutants that may cause or contribute to visibility impairment. Others potentially affected indirectly by this rule include members of the general public who live, work or recreate in mandatory Class I areas affected by visibility impairment. Because emission sources that contribute to visibility impairment in Class I areas also may contribute to air pollution in other areas, members of the general public may also be affected by

[1] The EPA's visibility protection regulations may apply, as appropriate under the Tribal Authority Rule (TAR) in 40 CFR part 49, to an Indian tribe that receives a determination of eligibility for treatment as a state for purposes of administering a tribal visibility protection program under section 169A of the CAA. No tribe has applied for such status, and so at present the EPA is responsible for implementation of the visibility protection regulations in areas of tribal authority. This responsibility includes, but is not limited to, implementation of the reasonable progress requirements of 40 CFR 51.308(f), as necessary or appropriate. These rule changes may impact the development and approvability of tribal implementation plans that tribes may wish to submit in the future. We encourage states to provide outreach and engage in discussions with tribes about their regional haze SIPs as they are being developed.

[2] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. CAA section 162(a). In accordance with section 169A of the CAA, the EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. CAA section 162(a). Although states and tribes may designate as Class I additional areas that they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." CAA section 302(i). When we use the term "Class I area" in this action, we mean any one of the 156 "mandatory Class I Federal areas" where visibility has been identified as an important value, unless the context makes it clear that additional non-mandatory Federal Class I areas are also meant to be included.

this rulemaking.

C. Obtaining a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of this *Federal Register* document will be posted at *http://www.epa.gov/visibility*. A "track changes" version of the full regulatory text that incorporates and shows the full context of the changes in this final action is also available in the docket for this rulemaking. In addition to the final and regulatory text documents, other relevant documents are located in the docket, including technical support documents referenced in this preamble.

D. Judicial Review

Under CAA section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by **[INSERT DATE 60 DAYS FROM DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

E. Organization of this Federal Register Document

The information presented in this document is organized as follows:

I. General Information
- A. Preamble Glossary of Terms and Acronyms
- B. Entities Affected by This Rule
- C. Obtaining a Copy of This Document and Other Related Information
- D. Judicial Review
- E. Organization of this *Federal Register* Document
- F. Background on this Rulemaking

II. Executive Summary

III. Overview of Visibility Protection Statutory Authority, Regulation and Implementation
- A. Visibility in Mandatory Class I Federal Areas
- B. Reasonably Attributable Visibility Impairment

C. Regional Haze
D. Air Permitting
IV. Final Rule Revisions
A. Ongoing Litigation in *Texas v. EPA*
B. Cooperative Federalism
C. Clarifications to Reflect the EPA's Long-Standing Interpretation of the Relationship Between Long-Term Strategies and Reasonable Progress Goals
D. Other Clarifications and Changes to Requirements for Periodic Comprehensive Revisions of Implementation Plans
E. Changes to Definitions and Terminology Related to How Days Are Selected for Tracking Progress
F. Impacts on Visibility from Anthropogenic Sources Outside the U.S.
G. Impacts on Visibility from Wildland Fires
H. Clarification of and Changes to the Required Content of Progress Reports
I. Changes to Reasonably Attributable Visibility Impairment Provisions
J. Consistency Revisions Related to Permitting of New and Modified Major Sources
K. Changes to FLM Consultation Requirements
L. Extension of Next Regional Haze SIP Deadline from 2018 to 2021
M. Changes to Scheduling of Regional Haze Progress Reports
N. Changes to the Requirement that Regional Haze Progress Reports be SIP Revisions
O. Changes to Requirements Related to the Grand Canyon Visibility Transport Commission
V. Environmental Justice Considerations
VI. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act (CRA)
VII. Statutory Authority

F. Background on this Rulemaking

On May 4, 2016, the EPA proposed revisions to the 1999 Regional Haze Rule (RHR),[3] which include clarifications and modifications to the requirements that states (and, if applicable, tribes) have to meet as they implement programs for the protection of visibility in mandatory Class I Federal areas, under sections 169A and 169B of the CAA. The EPA held public hearings on May 19, 2016, in Washington, D.C. and on June 1, 2016, in Denver, Colorado. States, industry, private citizens and non-governmental organizations submitted over 180,000 comments. Based on EPA's review of the comments, we are finalizing most of the proposed revisions, but are also making some changes to respond to the concerns raised by commenters. These include: changes to the proposed terminology used to refer to emissions inventories; changes to the proposed definitions and terminology related to how days are selected for tracking progress; changes to the proposed fire-related definitions and terminology; changes to the proposed required content of progress reports; changes to the proposed deadline for a state response to a reasonably attributable visibility impairment certification; the addition of a requirement for FLMs to consult with states prior to making a reasonably attributable visibility impairment certification; and minor changes to the requirements for FLM consultation on SIPs and progress reports.

II. Executive Summary

The CAA's visibility protection program, implemented through the rules at 40 CFR 51.300 through 51.309, helps to protect clear views in national parks, such as Grand Canyon National Park, and wilderness areas, such as the Okefenokee National Wildlife Refuge. Vistas in

---

[3] Here and elsewhere in this document, the terms "Regional Haze Rule," "1999 Regional Haze Rule" and "1999 RHR" refer to the 1999 final rule (64 FR 35714), as amended in 2005 (70 FR 39156, July 6, 2005), 2006 (71 FR 60631, October 13, 2006) and 2012 (77 FR 33656, June 7, 2012).

these areas are often obscured by visibility-impairing pollutants caused by emissions from numerous sources located over a wide geographic area. States are required to submit periodic plans demonstrating how they have and will continue to make progress towards achieving their visibility improvement goals. The first state plans were due in 2007 and covered the 2008-2018 planning period.

The EPA is making changes to the requirements that states (and, if applicable, tribes) have to meet for the second and subsequent implementation periods as they develop programs for the protection of visibility in mandatory Class I areas, consistent with CAA requirements. Implementation of the EPA's RHR (during the first implementation period) resulted in significant reductions in emissions and associated improvements in visibility in many Class I areas (*see* Section III.B of this document). This final rule supports continued environmental progress by retaining much of the 1999 RHR, clarifying or revising certain provisions of the visibility protection rules in 40 CFR part 51, subpart P, and removing rule provisions that have been superseded by subsequent developments. An overview of the revisions is provided later, with additional details throughout this document.

The EPA is clarifying the relationship between long-term strategies and RPGs in state plans and the long-term strategy obligations of all states. We are re-iterating that the CAA requires states to consider the four statutory factors (costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts and remaining useful life) in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class I area. The rate of progress in some Class I areas may be meeting or exceeding the uniform rate of progress (URP) that would lead to natural visibility conditions by 2064, but this does not excuse states from conducting the required analysis and determining whether additional progress would be reasonable based on the four factors. The EPA is revising the RHR to address a number of issues, as discussed in the proposal, including: the way in which a set of days during each year is to be selected for purposes of tracking progress towards natural visibility conditions; aspects of the requirements for the content of progress reports; updating, simplifying and extending to all states the provisions for reasonably attributable visibility impairment and revoking FIPs adopted in the 1980s that require the EPA to assess and address any existing reasonably attributable visibility impairment situations in some states; and revising the requirement for states to consult with FLMs. Other changes address administrative aspects of the program in order to reduce unnecessary burden. These include the following: the EPA is finalizing a one-time adjustment to the due date for the next SIPs (from 2018 to 2021); revising the due dates for progress reports; and changing the requirement that progress reports be submitted as formal SIP revisions to documents that need not comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103 and Appendix V to Part 51 – Criteria for Determining the Completeness of Plan Submissions. All of these changes apply to periodic comprehensive state implementation plans developed for the second and subsequent implementation periods and to progress reports submitted subsequent to those plans. These changes do not affect the development and review of state plans for the first implementation period or the first progress reports due under the 1999 RHR.

The rationale for these changes is described more fully in the descriptions of each change detailed later in this action as well as in the preamble to the proposed rule.[4] The revisions being finalized are informed by approximately 15 years of implementation of the CAA, numerous

[4] 81 FR 26942 (May 4, 2016).

outreach sessions and stakeholder feedback regarding the regional haze program, and the many constructive comments we received on the proposal. The clarifications regarding the relationship between RPGs, long-term strategies and the long-term strategy obligation of all states are intended to ensure appropriate and consistent understanding of these requirements as states prepare their plans for the second implementation period. These clarifications reflect EPA's long-standing interpretation of the RHR, and are now being codified. The rule revisions related to how days are selected for visibility progress tracking will provide the public and state officials more meaningful information on how existing and potential new emission reduction measures are contributing or could contribute to reasonable progress in reducing man-made visibility impairment. Changes to FLM consultation requirements will help ensure that the expertise and perspective of these officials are brought into the state plan development process early enough that they can meaningfully contribute to the state's deliberations. Collectively, the changes being finalized now will ensure that the regional haze program is implemented consistent with CAA obligations, and ensure successful implementation during the second planning period and beyond.

With regard to the extension of the deadline of July 31, 2018, to July 31, 2021, for states' comprehensive SIP revisions for the second implementation period, this one-time change will benefit states by allowing them to obtain and take into account information on the effects of a number of other regulatory programs that will be impacting sources over the next several years. The change will also allow states to develop SIP revisions for the second implementation period that are more integrated with state planning for these other programs, an advantage that was widely confirmed in early discussions with states and in comments submitted to the docket for this rulemaking. We anticipate that this change will result in greater environmental progress than if planning for these multiple programs were not as well integrated. The end date for the second implementation period remains 2028, as was required by the 1999 RHR. Other than the one-time change to the next due date for periodic comprehensive SIP revisions, no change is being made for due dates for future periodic comprehensive SIP revisions.

The changes related to progress reports are intended to make the timing of progress reports more useful as mid-course reviews, to clarify the required content of progress reports for aspects on which there has been some confusion, and to allow states to conserve their administrative resources and make submission of progress reports more timely by removing the requirement that they be submitted as formal SIP revisions. We are retaining a requirement that states consult with FLMs on their progress reports, and that states offer the public an opportunity to comment on progress reports before they are finalized, which are two of the steps that applied to progress reports when they were required to be SIP revisions, and which will help ensure ongoing accountability for progress reports. Please note that while the proposed rule included identical FLM consultation periods for progress reports and periodic comprehensive SIP revisions, FLM consultation requirements for SIP revisions and progress reports will differ going forward. This issue is described more fully in Section IV.K of this document.

Finally, the 1999 RHR's provisions related to reasonably attributable visibility impairment required a recurring process of assessment and planning by the states. Experience since these provisions were promulgated suggests that situations involving reasonably attributable visibility impairment occur infrequently and therefore that an "as needed" approach for initiating a state planning obligation would be a more efficient use of resources. The EPA is finalizing its proposal to replace the recurring process of assessment of reasonably attributable visibility impairment with an as-needed approach. The change to an as-needed approach only applies to reasonably attributable visibility impairment – periodic planning for purposes of regional haze will continue. In addition, in light of our increased understanding of the interstate nature of visibility impairment, we are expanding the applicability of the requirement to address reasonably attributable visibility impairment from only states with Class I areas to all states. If a situation exists or arises in which a source or a small number of sources in a state without any Class I area causes reasonably attributable visibility impairment at a Class I area in another state, this mechanism will ensure adequate visibility protection.

III. Overview of Visibility Protection Statutory Authority, Regulation and Implementation

A. Visibility in Mandatory Class I Federal Areas

Reduction in visibility caused by emissions of PM_{10}, $PM_{2.5}$ (e.g., sulfates, nitrates, organic carbon, elemental carbon and soil dust) and their precursors (e.g., SO_2, NO_x and, in some cases, ammonia and volatile organic compounds) can take the form of either visibly distinct layers or plumes of pollution or more uniform "regional haze." Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which along with directly emitted PM_{10} and $PM_{2.5}$ impairs visibility by scattering and absorbing light. This light scattering reduces the clarity, color and visible distance that one can see. Particulate matter can also cause serious health effects in humans (including premature death, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and increased respiratory symptoms) and contribute to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that at the time the

RHR was finalized in 1999, visibility impairment caused by air pollution occurred virtually all the time at most national park and wilderness areas. The formally defined average visual range[5] in many Class I areas in the western U.S. was 62–93 miles. In some Class I areas, these visual ranges may have been impacted by natural wildfire and dust episodes in addition to anthropogenic impacts. In most of the eastern Class I areas of the U.S., the average visual range was less than 19 miles.[6]

Based on visibility data through 2014, the visual range has increased 10 to 20 miles (4 to 7 deciviews)[7] since the year 2000 in eastern Class I areas on the 20 percent haziest days. Some western Class I areas have also experienced visual range increases of 5 to 10 miles (1 to 4 deciviews) on the 20 percent haziest days. However, in some areas, such as Sawtooth Wilderness area in Idaho, improvements from reduced emissions from man-made sources have been overwhelmed by impacts from wildfire and/or dust events. There are also some western areas where visibility has improved only by a slight amount or made no progress.

B. Reasonably Attributable Visibility Impairment

---

[5] Visual range is the greatest distance, in kilometers or miles, at which a certain dark object can be discerned against the sky by a typical observer under certain defined conditions. Visual range defined in this highly controlled manner is inversely proportional to light extinction (b_{ext}) by particles and gases and is calculated as: Visual Range = $3.91/b_{ext}$ (Bennett, M.G., The physical conditions controlling visibility through the atmosphere; Quarterly Journal of the Royal Meteorological Society, 1930, 56, 1-29). Light extinction has units of inverse distance (i.e., Mm^{-1} or inverse Megameters (mega = 10^6)). Under conditions other than those defined in this reference, people's ability to discern landscape features may vary and be different than implied by the value of the visual range as calculated from light extinction using this formula.

[6] 64 FR 35715 (July 1, 1999).

[7] The deciview haze index (discussed in more detail in Section III.B.3 of this document) is logarithmically related to light extinction and is used by the regional haze program because it describes uniform differences in visibility across a range of visibility conditions.

In section 169A of the 1977 Amendments to the CAA, Congress enacted a program for protecting visibility in the nation's national parks, wilderness areas and other Class I areas due to their "great scenic importance."[8] Section 169A(a) of the CAA establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

In 1980, the EPA promulgated regulations to address visibility impairment in Class I areas, including but not limited to impairment that is "reasonably attributable" to a single source or small group of sources, i.e., "reasonably attributable visibility impairment."[9] These regulations, codified at 40 CFR 51.300 through 51.307, represented the first phase in addressing visibility impairment from existing sources. They also addressed potential visibility impacts from new and modified major sources already subject to permitting requirements for purposes of protection of the National Ambient Air Quality Standards (NAAQS) and preventing significant deterioration of air quality.

Notably, not all states were subject to the 1980 reasonably attributable visibility impairment requirements. Under the 1980 rules, the 35 states and one territory (Virgin Islands) containing Class I areas were required to submit SIPs addressing reasonably attributable visibility impairment. The 1980 rules required states to (1) develop, adopt, implement and evaluate long-term strategies for making reasonable progress toward remedying existing and preventing future impairment in the mandatory Class I areas through their SIP revisions; (2) adopt certain measures to assess potential visibility impacts due to new or modified major stationary sources, including measures to notify FLMs of proposed new source permit

[8] H.R. Rep. No. 294, 95th Cong. 1st Sess. at 205 (1977).
[9] 45 FR 80084 (December 2, 1980).

applications, and to consider visibility analyses conducted by FLMs in their new source permitting decisions; (3) conduct visibility monitoring in mandatory Class I areas, and (4) revise their SIPs at 3-year intervals to assure reasonable progress toward the national visibility goal. In addition, the 1980 regulations provided that an FLM may certify to a state at any time that visibility impairment at a Class I area is reasonably attributable to a single source or a small number of sources. Following such a certification by an FLM, a state was required to address the requirements for best available retrofit technology (BART) for BART-eligible sources considered to be contributing to reasonably attributable visibility impairment. Also, the appropriate control of any source certified by an FLM, whether BART-eligible or not, would be specifically addressed in the long-term strategy for making reasonable progress toward the national goal of natural visibility conditions. *See* the 1980 rule's version of 40 CFR 51.302(c)(2)(i).

In practice, the 1980 rules resulted in few SIPs being submitted by states and approved by the EPA, requiring the EPA to develop and apply FIPs to those states that failed to submit an approvable reasonably attributable visibility impairment SIP.[10] Most of these FIPs contained planning requirements only. That is, most of the FIPs merely committed the EPA to assessing on a 3-year cycle whether reasonably attributable visibility impairment was occurring, and if so, to adopting an appropriate strategy of required emission controls.

C. Regional Haze

1. Requirements of the 1990 CAA Amendments and the EPA's Regional Haze Rule

[10] 52 FR 45132 (November 24, 1987).

In 1990, Congress added section 169B to the CAA to further address regional haze issues. Among other things, this section included provisions for the EPA to conduct visibility research on regional regulatory tools with the National Park Service and other federal agencies, and to provide periodic reports to Congress on visibility improvements due to implementation of other air pollution protection programs. CAA section 169B also generally allowed the Administrator to establish visibility transport commissions and specifically required the Administrator to establish a commission for the Grand Canyon area. The EPA promulgated a rule to address regional haze in 1999.[11] The 1999 RHR established a more comprehensive visibility protection program for Class I areas. The requirements for regional haze are found at 40 CFR 51.308 and 51.309.

The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands.[12] Congress subsequently amended the deadlines for regional haze SIPs, and the EPA adopted regulations requiring states to submit the first implementation plans addressing regional haze visibility impairment no later than December 17, 2007.[13] These initial SIPs were to address emissions from certain large stationary sources and other requirements, which we discuss in greater detail later. Few states submitted a regional haze SIP by the December 17, 2007, deadline, and on January 15, 2009, the EPA found that 37 states, the District of Columbia and the Virgin Islands had failed to submit SIPs addressing the regional

[11] 64 FR 35714 (July 1, 1999).
[12] This requirement does not apply to other U.S. territories defined as "states" under the CAA because they do not have mandatory Class I Federal areas and are too distant from any such areas to affect them.
[13] 70 FR 39104 (July 6, 2005).

haze requirements.[14] These findings triggered a requirement for the EPA to promulgate FIPs within 2 years unless a state submitted a SIP and the EPA approved that SIP within the 2-year period.[15] Most states eventually submitted SIPs.

The 1999 RHR also required states to submit periodic comprehensive revisions of their regional haze SIPs. Under 40 CFR 51.308(f) of the 1999 RHR, states were required to submit the first such revision by no later than July 31, 2018, and every 10 years thereafter. These periodic comprehensive SIP revisions were required to address a number of elements, including current visibility conditions and actual progress made toward natural conditions during the previous implementation period; a reassessment of the effectiveness of the long-term strategy in achieving the RPGs over the prior implementation period; and affirmation of or revision to the RPGs. Further information on these periodic comprehensive SIP revisions can be found in Section III.B.3 of this document. In addition, the 1999 RHR's 40 CFR 51.308(g) required each state to submit progress reports, in the form of SIP revisions, every 5 years after the date of the state's initial SIP submission. In the progress reports, states were required to evaluate the progress made towards the RPGs for mandatory Class I areas located within the state, as well as those mandatory Class I areas located outside the state that may be affected by emissions from within the state. Further information on progress reports can be found in Section III.B.4 of this document.

The 1999 RHR sought to improve efficiency and transparency by requiring states to coordinate planning under the 1980 reasonably attributable visibility impairment provisions with planning under the provisions added by the 1999 RHR. The states were directed to submit

[14] 74 FR 2392 (January 15, 2009).
[15] CAA section 110(c).

reasonably attributable visibility impairment SIPs every 10 years rather than every 3 years, and to do so as part of the newly required regional haze SIPs. Many, but not all, states submitted initial regional haze SIPs that committed to this coordinated planning process. Coordination of reasonably attributable visibility impairment and regional haze planning is described in more detail later.

2. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program requires long-term regional coordination among states, tribal governments and various federal agencies. As noted earlier, pollution affecting the air quality in Class I areas is emitted from many individual sources and can be transported over long distances, even hundreds of miles. Therefore, to effectively address the problem of visibility impairment in Class I areas, states need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, and because these sources may be numerous and emit amounts of pollutants that, even though small, contribute to the collective whole, the EPA encourages states to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were formed after the promulgation of the RHR in 1999 to address regional haze and related issues: the Central Regional Air Planning Association, the Mid-Atlantic/Northeast Visibility Union, the Midwest Regional Planning Organization, the Western Regional Air Partnership and the Visibility Improvement State and Tribal Association of the

Southeast.[16] The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then supported the development (by states) of regional strategies to reduce emissions of pollutants that lead to regional haze.

3. Requirements for the Regional Haze SIPs

As mentioned earlier, states were required to submit SIPs addressing regional haze visibility impairment in 2007, which covered what we refer to as the first implementation period (2008-2018). A focus of the 2007 SIP obligation was to give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, by requiring these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing visibility impairment. These SIPs included a number of components and/or analyses, which are described later along with information regarding whether or not this final rule impacts that particular SIP element.

BART Requirement. Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to include such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources[17] procure, install and operate BART. Under the RHR, the EPA

---

[16] *See* "Visibility – Regional Planning Organizations," *available at https://www.epa.gov/visibility/visibility-regional-planning-organizations*.

[17] The set of "major stationary sources" potentially subject-to-BART is listed in CAA section 169A(g)(7).

directed states to conduct BART determinations for any "BART-eligible" sources[18] that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at appendix Y to 40 CFR part 51 (hereinafter referred to as the "BART Guidelines") to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source.[19] The 1999 RHR also gave states the flexibility to adopt an emissions trading program or other alternative program in lieu of source-specific BART as long as the alternative provided greater reasonable progress towards improving visibility than BART and met certain other requirements set out in the 1999 RHR's 40 CFR 51.308(e)(2).

States were required to undertake the BART determination process during the first implementation period. The BART requirement was a one-time requirement, but a BART-eligible source may need to be re-assessed for additional controls in future implementation periods under the CAA's reasonable progress provisions. Specifically, we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) will need to be reassessed. Under the 1999 RHR's 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional

[18] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were not in operation prior to August 7, 1962, but were in existence on August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. 40 CFR 51.301.
[19] 70 FR 39104 (July 6, 2005).

haze SIP requirements for the first implementation period, in the same manner as other sources going forward.[20]

Visibility Metric. The RHR established the 24-hour deciview haze index as the principal metric or unit for expressing visibility on any particular day.[21] The deciview haze index is calculated from light extinction values and expresses uniform changes in the degree of haze in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy. Deciview values are calculated by using air quality measurements to estimate light extinction, most recently using the revised IMPROVE algorithm, and then transforming the value of light extinction using a logarithmic function.[22] The deciview is a more useful measure for comparing days and tracking progress in improving visibility than light extinction itself because each deciview change is an equal incremental change in visibility typically perceived by a human observer. Most people can detect a change in visibility of one deciview. The preamble to the 1999 RHR provided additional details about the deciview haze index.

Baseline, Current and Natural Conditions and Tracking Changes in Visibility. To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401–437), and as part of the process for determining reasonable progress, states were required to calculate visibility conditions at each Class I area for a 5-year period just

---

[20] Under the 1999 RHR's 40 CFR 51.308(e)(5), BART-eligible sources were subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward.
[21] *See* 70 FR 39104, 39118.
[22] Pitchford, M.; Malm, W.; Schichtel, B.; Kumar, N.; Lowenthal, D.; Hand, J. Revised algorithm for estimating light extinction from IMPROVE particle speciation data; J. Air & Waste Manage. Assoc. 2007, 57, 1326-1336; doi: 3155/1047-3289.57.11.1326.

preceding each periodic comprehensive SIP revision.[23] To do this, the 1999 RHR required states to determine average visibility conditions (in deciviews) for the 20 percent least impaired days and the 20 percent most impaired days over the 5-year period at each of their Class I areas.

States were also required to develop an estimate of natural visibility conditions for the purpose of estimating progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. The EPA has provided guidance to states regarding how to calculate baseline, natural and current visibility conditions at each Class I area.[24] After the EPA issued this guidance, a number of interested parties together developed a set of alternative estimates of natural conditions using a more refined approach (known as "NC-II"), which were used by most states in their first regional haze SIPs with EPA approval.[25]

Baseline visibility conditions reflect the degree of visibility impairment for the 20 percent least impaired days and 20 percent most impaired days for each calendar year from 2000 to

---

[23] Under the 1999 RHR, states were also required to periodically review progress in reducing impairment every 5 years.

[24] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, September 2003, EPA–454/B–03–005, available at *http://www3.epa.gov/ttn/caaa/t1/memoranda/rh_envcurhr_gd.pdf*; and Guidance for Tracking Progress Under the Regional Haze Rule, September 2003, EPA–454/B–03–004, available at *http://www3.epa.gov/ttn/oarpg/t1/memoranda/rh_tpurhr_gd.pdf*.

[25] Regional Haze Rule Natural Level Estimates Using the Revised IMPROVE Aerosol Reconstructed Light Extinction Algorithm, available at *http://vista.cira.colostate.edu/improve/Publications/GrayLit/032_NaturalCondIIpaper/Copeland_etal_NaturalConditionsII_Description.pdf;* Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data, available at *http://vista.cira.colostate.edu/improve/Publications/GrayLit/019_RevisedIMPROVEeq/RevisedIMPROVEAlgorithm3.doc;* and Regional Haze Data Analysis Workshop, June 8, 2005, Denver, CO, agenda and documents available at *http://www.wrapair.org/forums/aamrf/meetings/050608den/index.html.*

2004. Using monitoring data for 2000 through 2004, states are required to calculate the average degree of visibility impairment for each Class I area, based on the average of annual values of these two metrics over the 5-year period. The comparison of baseline visibility conditions to natural visibility conditions indicates the amount of improvement that would be necessary to attain natural visibility. Over time, the comparison of current visibility conditions[26] to the baseline visibility conditions will indicate the amount of progress that has been made.

The 1999 RHR defined "visibility impairment" as a humanly perceptible change (i.e., difference) in visibility from that which would have existed under natural conditions. The rule directed the tracking of visibility impairment on the 20 percent "most impaired days" and 20 percent "least impaired days" in order to determine progress towards natural visibility conditions. 40 CFR 51.308(d)(2)(i-iv). In light of the 1999 RHR's definition of "impairment," the term "impaired" in the phrases "most impaired days" and "least impaired days" could be taken to mean anthropogenic impairment only and to exclude reductions in visibility attributable to natural emission sources. However, the preamble to the 1999 RHR stated that the least and most impaired days were to be selected as the monitored days with the lowest and highest actual deciview levels caused by all sources, respectively. In 2003, the EPA issued guidance describing in detail the steps necessary for selecting and calculating light extinction on the "worst" and "best" visibility days, and this guidance also indicated that the monitored days with the lowest and highest actual deciview levels were to be selected as the least and most impaired days.[27] This

---

[26] Given the required timing of the first regional haze SIPs that were due by December 17, 2007, "baseline visibility conditions" were also the "current" visibility conditions. For future SIPs, "current conditions" will be updated to the 5-year period just preceding the SIP revision.
[27] Guidance for Tracking Progress Under the Regional Haze Rule, September 2003, *http://www3.epa.gov/ttnamti1/files/ambient/visible/tracking.pdf.*

approach worked well in many Class I areas but caused some concerns in other areas. Specifically, the "worst" visibility days in some Class I areas can be impacted by irregularly occurring natural emissions (e.g., wildland wildfires and dust storms). These natural contributions to haze vary in magnitude and timing. Anticipating this variability, in the 1999 RHR the EPA decided to use 5-year averages of visibility data to minimize the impacts of the interannual variability in natural events. However, additional data available through the IMPROVE monitoring network indicate that in many Class I areas 5-year averages are not sufficient for minimizing these erratic impacts. As a result, visibility improvements resulting from decreases in anthropogenic emissions can be hidden by this natural variability. Further, because of the logarithmic deciview scale, changes in PM concentrations and light extinction due to reductions in anthropogenic emissions have little effect on the deciview value on days with high PM concentrations and light extinction due to natural sources. The use of the days with the highest deciview index values, without consideration of the source of the visibility impacts, thus created difficulties when attempting to track visibility improvements resulting from controls on anthropogenic sources. States identified this difficulty prior to the start of this rulemaking and asked that the EPA explore options for focusing the visibility tracking metric on the effect of controlling anthropogenic emissions. To help states minimize the impacts of emissions from natural sources on visibility tracking via an approach that is also consistent with the CAA's goal to reduce visibility impairment resulting from man-made air pollution, the EPA proposed to more explicitly (and consistently) address this issue for future implementation periods.

Reasonable Progress Goals and Long-Term Strategy. To ensure continuing progress towards achieving the natural visibility goal, the 1999 RHR required that each SIP submission in the series of periodic comprehensive regional haze SIPs establish two distinct RPGs (one for the most impaired and one for the least impaired days) for every Class I area. *See* 40 CFR 51.308(d)(1). The 1999 RHR did not mandate specific milestones or rates of progress, but instead called for states to establish goals that provide for "reasonable progress" toward achieving natural visibility conditions. Specifically, states were required to provide for an improvement in visibility for the most impaired days over the period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period.

To set their RPGs, states were required to consider the four statutory reasonable progress factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. States were required to demonstrate in their SIPs how these factors were considered when selecting the RPGs for the least impaired and most impaired days for each applicable Class I area. The RPGs are not enforceable.[28]

Consistent with the requirement in section 169A(b) of the CAA that states include in their regional haze SIPs a 10- to 15-year strategy for making reasonable progress, 40 CFR 51.308(d)(3) of the 1999 RHR required states to include a long-term strategy in their regional haze SIPs. Under the 1999 RHR, a state's long-term strategy is inextricably linked to the RPGs because the long-term strategy "must include enforceable emission limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by states having mandatory Class I Federal areas." 40 CFR 51.308(d)(3).

When setting their RPGs, states were also required to consider the rate of progress for the most impaired days that would be needed to reach natural visibility conditions by 2064 and the

---

[28] 64 FR 35754.

emission reduction measures that would be needed to achieve that rate of progress over the approximately 10-year period of the SIP. The purpose of this requirement was to allow for analytical comparisons between the rate of progress that would be achieved by the state's chosen set of control measures and the URP. If a state's RPG for the most impaired days achieved progress that was equal to the URP, the RPG would be "on the URP line"[29] or "on the glidepath." If a state's RPG for the most impaired days was not on the glidepath, 40 CFR 51.308(d)(1)(ii) required the state to demonstrate that it would not be reasonable to require additional control measures and adopt an RPG that would be on the glidepath. The 1999 RHR did not establish an enforceable requirement that natural conditions be reached by 2064. The EPA approved a number of SIPs for the first implementation period that projected that continued progress at the rate expected to be achieved during the first period would not result in natural conditions until after 2064 However, the EPA also disapproved some SIPs during the first implementation period where states argued that no analysis of the four factors was necessary because visibility was projected to be "below the glidepath" at the end of the implementation period even without additional measures.[30]

In setting their RPGs, each state with one or more Class I areas was also required to consult with potentially "contributing states," i.e., other nearby states with emission sources that may be affecting visibility impairment in the state's Class I areas. In such cases, the contributing state was required to demonstrate that it included in its long-term strategy all measures necessary

---

[29] The URP for the most impaired days can be represented in a graphical manner by drawing the "URP line" on a chart with calendar year on the horizontal axis and deciviews for the 20 percent most impaired day on the vertical axis.
[30] 76 FR 64186 at 64195 (October 17, 2011) (proposed action on Arkansas's RPGs), 77 FR 14604 at 14612 (March 12, 2012) (final action on Arkansas's RPGs).

to obtain its share of the emission reductions needed to make reasonable progress at the Class I area.[31] In determining whether the upwind and downwind states' long-term strategies and RPGs provided for reasonable progress toward natural visibility conditions, the EPA was required to evaluate the demonstrations developed by the state. 40 CFR 51.308(d)(1).

The 1999 RHR required states to consider all types of anthropogenic sources of visibility impairment when developing their long-term strategies, including major and minor stationary sources, mobile sources and area sources. States had to consider a number of factors when developing their long-term strategies, including: (1) emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes; (6) the enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area and mobile source emissions over the period addressed by the long-term strategy. 40 CFR 51.308(d)(3)(v).

Coordinating Regional Haze and Reasonably Attributable Visibility Impairment. The 1999 RHR fulfilled the EPA's responsibility to put in place a national regulatory program that addresses both reasonably attributable visibility impairment and regional haze. As part of the

[31] This consultation obligation is a key element of the regional haze program. Congress, the states, the courts and the EPA have long recognized that regional haze is a regional problem that requires regional solutions. *Vermont v. Thomas,* 850 F.2d 99, 101 (2d Cir. 1988). Ultimately, early actions by states such as Vermont were influential in Congressional enactment of section 169B of the CAA in 1990. Congress intended this provision of the CAA to "equalize the positions of the States with respect to interstate pollution," (S. Rep. No. 95-127, at 41 (1977)) and our interpretation accomplishes this goal by ensuring that downwind states can seek recourse from us if upwind states are not doing enough to address visibility transport.

1999 RHR, the EPA revised the schedule in 40 CFR 51.306(c) for the periodic review of reasonably attributable visibility impairment SIPs. The revised version of this subsection required that the reasonably attributable visibility impairment plan must continue to provide for a periodic review and SIP revision not less frequently than every 3 years until the date of submission of the state's first plan addressing regional haze visibility impairment. On or before this date, the state must have revised its plan to provide for periodic review and revision of a coordinated long-term strategy for addressing reasonably attributable visibility impairment and regional haze, and the state must have submitted the first such coordinated long-term strategy with its first regional haze SIP. Under the 1999 RHR, states were required to submit future coordinated long-term strategies, and periodic progress reports evaluating progress towards RPGs. The state's periodic review of its long-term strategy was required to report on both regional haze visibility impairment and reasonably attributable visibility impairment and was required to be submitted to the EPA in the form of a periodic comprehensive SIP revision. Under our proposed changes to the reasonably attributable visibility impairment provisions, this coordinated approach to a state's long-term strategies for regional haze and reasonably attributable visibility impairment would continue, but will apply in the infrequent case that a state receives a certification of reasonably attributable visibility impairment.

Monitoring Strategy and Other Implementation Plan Requirements. 40 CFR 51.308(d)(4) of the 1999 RHR included the requirement for a monitoring strategy for measuring, characterizing and reporting of regional haze visibility impairment that is representative of all mandatory Class I areas within the state. The strategy was required to be coordinated with the monitoring strategy required in the 1999 RHR version of 40 CFR 51.305 for reasonably attributable visibility impairment. Compliance with this requirement could be met through “participation” in the IMPROVE network.[32] A state’s participation in the IMPROVE network includes state support for the use of CAA state and tribal assistance grants funds to partially support the operation of the IMPROVE network as well as the state’s review and use of monitoring data from the network. The monitoring strategy was due with the first regional haze SIP, and under the 1999 RHR it must be reviewed every 5 years as part of the progress reports. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met. To date, neither the EPA nor any state has concluded that the IMPROVE network is not sufficient in this way. The evolution of the IMPROVE network will be guided by a Steering Committee that has FLM, EPA and state participation, within the evolving context of available resources. It is the EPA’s objective that individual states will not be required to commit to providing monitoring sites beyond those planned to be operated by the IMPROVE program during the period covered by a SIP revision. Further, if the IMPROVE program must discontinue a monitoring site, this would not be a basis for an approved regional haze SIP to be found inadequate; but rather, the state, the federal agencies and the IMPROVE Steering Committee should work together to address the RHR requirements when the next SIP revision is developed. As described in Section IV.H of this document, we proposed that progress reports from individual states no longer be required to review and modify as necessary the state’s monitoring strategy. The IMPROVE Steering Committee structure, the requirement to review the monitoring strategy as part of the periodic comprehensive SIP revision, and the requirement for a state to consider any recommendations

[32] While compliance with 40 CFR 51.308(d)(4) for regional haze may be met through participation in the IMPROVE network, additional analysis or techniques beyond participation in IMPROVE may be required for compliance with 40 CFR 51.305 for reasonably attributable visibility impairment.

from the EPA or a FLM for additional monitoring for purposes of reasonably attributable visibility impairment will be sufficient to achieve the objective of the current progress report requirement to review the monitoring strategy.

Consultation between States and FLMs. The 1999 RHR required that states consult with FLMs before adopting and submitting their SIPs. 40 CFR 51.308(i). There are two parts to this requirement. First, states must provide FLMs an opportunity for an in-person consultation meeting at least 60 days prior to holding any public hearing on the SIP. This consultation meeting was required to include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment. Further, a state was required to include in its SIP a description of how it addressed any comments provided by the FLMs. We proposed to require that states offer the opportunity for this already-required in-person consultation meeting early enough that information and recommendations provided by the FLMs can meaningfully inform the state's decisions on the long-term strategy. The second part of the consultation requirement is that a SIP must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas. We did not propose any change to this requirement for procedures for continuing consultation. This continuing consultation should provide opportunities for FLM input on the scope and methods for the state's technical analyses as they are being planned, while the in-person consultation meeting required by the first part of the consultation requirement will occur as a state is making decisions based on the conclusions of its technical analyses. FLMs often participate in multi-state workgroups on regional haze and related issues and attend multi-state meetings on these topics, which further facilitates collaboration with individual states during SIP development.

4. Requirements for the Regional Haze Progress Reports

The 1999 RHR included provisions for progress reports to be submitted at 5-year intervals, counting from the submission of the first required SIP revision by the particular state. The requirements for these reports were included for most states in 40 CFR 51.308 (g) and (h). Three western states (New Mexico, Utah and Wyoming) exercised an option provided in the RHR to meet alternative requirements contained in 40 CFR 51.309 for their SIPs. For these three states, the requirements for the content of the 5-year progress reports are identical to those for the other states, but for these states the requirements for the reports were contained in 40 CFR 51.309(d)(10). This section specifies fixed due dates in 2013 and 2018 for these progress reports. The 1999 RHR then provided that these three states will revert to the progress report requirements in 40 CFR 51.308 after the report currently due in 2018. We did not propose this aspect of the RHR.

An explanation of the 5-year progress reports is provided in the preamble to the 1999 RHR.[33] This 5-year review was intended to provide an interim report on the implementation of, and if necessary mid-course corrections to, the regional haze SIP, which is generally prepared in 10-year increments. The progress report provides an opportunity for public input on the state's (and the EPA's) assessment of whether the approved regional haze SIP is being implemented

[33] 64 FR 35747 (July 1, 1999).

appropriately and whether reasonable visibility progress is being achieved consistent with the projected visibility improvement in the SIP.

Required elements of the progress report under the 1999 RHR included: the status of implementation of all measures included in the regional haze SIP; a summary of the emissions reductions achieved throughout the state; an assessment of current visibility conditions and the change in visibility impairment over the past 5 years; an analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the state; an assessment of any significant changes in anthropogenic emissions within or outside the state that have occurred over the past 5 years that have limited or impeded progress in reducing pollutant emissions and improving visibility; an assessment of whether the current SIP elements and strategies are sufficient to enable the state (or other states with mandatory Class I areas affected by emissions from the state) to meet all established RPGs; a review of the state's visibility monitoring strategy and any modifications to the strategy as necessary; and a determination of the adequacy of the existing SIP (including taking one of four possible actions).[34] We proposed to include a number of clarifications and changes to the requirements for the content of progress reports.

Under the 1999 RHR's 40 CFR 51.308(g) and 40 CFR 51.309(d)(10), progress reports must take the form of SIP revisions, so states must follow formal administrative procedures (including public review and opportunity for a public hearing) before formally submitting the 5-

---

[34] 40 CFR 51.308(g). *See* also General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports), April 2013, EPA–454/B–03–005, available at *https://www.epa.gov/sites/production/files/2016-03/documents/haze_5year_4-10-13.pdf*, (hereinafter referred to as "our 2013 Progress Report Guidance").

year progress report to the EPA. *See* 40 CFR 51.102, 40 CFR 51.103, and Appendix V to Part 51 – Criteria for Determining the Completeness of Plan Submissions. We proposed to remove the requirement that progress reports be submitted as SIP revisions.

In addition, because progress reports were SIP revisions under the 1999 RHR, states were required to provide FLMs with an opportunity for in-person consultation at least 60 days prior to any public hearing on progress report. *See* 1999 RHR version of 40 CFR 51.308(i)(2) and (3). Procedures must also be provided for continuing consultation between the state and FLM regarding development and review of progress reports. *See* 40 CFR 51.308(i)(4).

Under the 1999 RHR, the first progress reports were due 5 years from the initial SIP submittal (with the next progress reports for New Mexico, Utah, and Wyoming due in 2018). Most of these deadlines have already passed although some are due in 2016 and in 2017.[35]

5. Tribes and Regional Haze

Tribes have a distinct interest in regional haze due to the effects of visibility impairment on tribal lands as well as on other lands of high value to tribal members, such as landmarks considered sacred. Tribes, therefore, have a strong interest in emission control measures that states and the EPA incorporate into SIPs and FIPs with regard to regional haze, and also have an interest in the state response to any certification of reasonably attributable visibility impairment

[35] A number of first progress reports have been submitted by states. Several of these progress reports have been approved, action on several others has been proposed, and EPA is still reviewing the other submitted reports. There are also states for which progress reports are overdue, and a few states for which progress reports are not yet due and have not been submitted.

made by an FLM.[36] The agency has a tribal consultation policy that covers any plan that the EPA would promulgate that may affect tribal interests. This consultation policy applies to situations where a potentially affected source is located on tribal land, as well as situations where a SIP or FIP concerns a source that is located on state land and may affect tribal land or other lands that involve tribal interests. In addition, the EPA has and will continue to consider any tribal comments on any proposed action on a SIP or FIP.

In the first implementation period for regional haze SIPs, the partnerships within the RPOs included strong relationships between the states and the tribes, and the EPA encourages states to continue to invest in those relationships (including consulting with tribes), particularly with respect to tribes located near Class I areas. States should continue working directly with tribes on their SIPs and their response to any certification of reasonably attributable visibility impairment made by an FLM. It is preferable for states to address tribal concerns during their planning process rather than the EPA addressing such concerns in its subsequent rulemaking process. During the development of this rulemaking, the EPA was asked by the National Tribal Air Association to adopt a requirement that states formally consult with tribes during the development of their regional haze SIPs. The CAA does not explicitly authorize the EPA to impose such a requirement on the states. While we recognize the value of dialogue between state and tribal representatives, we did not propose to require it.

D. Air Permitting

---

[36] Like the EPA, the Department of the Interior and the U.S. Forest Service in the U.S. Department of Agriculture have strong tribal consultation policies. *See*: *http://www.epa.gov/tribal/consultation/index.htm*; *http://www.fs.fed.us/spf/tribalrelations/authorities.shtml*, and *https://www.doi.gov/tribes/Tribal-Consultation-Policy.*

One part of the visibility protection program, 40 CFR 51.307, New Source Review (NSR), was established in 1980 with the rationale that while most new sources that may impair visibility were already subject to review under the Prevention of Significant Deterioration provisions (part C of Title I of the CAA), additional regulations would "ensure that certain sources exempt from the PSD regulations because of geographic criteria will be adequately reviewed for their potential impact on visibility in the mandatory Class I Federal area."[37] The EPA explained at proposal that this was necessary because the PSD regulations did not call for the review of major emitting facilities (or major modifications) located in nonattainment areas,[38] and that it was appropriate to "clarify certain procedural relationships between the FLM and the state in the review of new source impacts on visibility in Federal class I areas."[39] The EPA envisioned that state and FLM consultation would commence with the state notifying the FLM of a potential new source, and that consultation would continue throughout the permitting process. We proposed to revise 40 CFR 51.307 only as needed to maintain consistency with revisions to other sections of 40 CFR part 50 subpart P.

IV. Final Rule Revisions

[37] 45 FR 80084 (December 2, 1980).

[38] In 1978, PSD rules were put in place that required permitting agencies to interact with FLMs and for air quality related values (AQRVs) to be taken into consideration in the PSD permitting process. 43 FR 26380 (June 19, 1978). Those PSD rules did not cover sources in nonattainment areas, and while there were EPA rules for nonattainment NSR in existence, they did not require consideration of Class I areas. In 1979, 40 CFR part 51, appendix S established rules for nonattainment permitting, but they did not (and still do not) require consideration of visibility or FLM notification. (The same is also true of a more recent addition, 40 CFR 51.165. Where applicable to nonattainment areas, this rule does not require Class I reviews. While 40 CFR 51.165(b) requires that sources located in attainment areas cannot cause or contribute to a NAAQS violation anywhere, this does not cover AQRVs in Class I areas.) As a result, in 1980, the EPA added requirements to 40 CFR 51.307 for notification of FLMs of pending permits for new sources in nonattainment areas.

[39] 45 FR 34765 (May 22, 1980).

The EPA is finalizing revisions to the agency's visibility regulations that are intended to build upon the progress achieved by the visibility program over the last decade while streamlining certain administrative requirements that are unnecessarily burdensome. The EPA gained a substantial amount of knowledge during the first regional haze implementation period and learned what aspects of the program work well and what aspects could benefit from modification. The EPA received information and perspectives from air agencies and FLMs during this period that were invaluable in developing the proposal. We also received comments from a wide variety of other stakeholders during the public comment process, including groups of states, FLMs, industry and industry representatives, nongovernmental organizations, and others. We considered all timely comments submitted on the proposal and address many of the most significant comments in this section. We are also providing a separate response-to-comments (RTC) document in the docket for this rulemaking. Between this preamble and the RTC document, we have responded to all significant comments received on this rulemaking.

A. Ongoing Litigation in Texas v. EPA

A number of state and industry stakeholders submitted comments regarding the ongoing litigation in the Fifth Circuit Court of Appeals over the EPA's January 2016 final action that partially approved and partially disapproved the Oklahoma and Texas regional haze SIPs for the first implementation period and promulgated partial FIPs for each state.[40] These commenters asserted that the Fifth Circuit's decision granting a stay[41] of the Texas FIP's reasonable progress emission limits undermined our proposed revisions to the visibility regulations. Some

[40] 81 FR 295 (January 5, 2016).

[41] *Texas v. EPA*, 2016 U.S. App. LEXIS 13058 (5th Cir. July 15, 2016).

commenters also suggested that we must suspend our rulemaking revising the visibility regulations until after the Fifth Circuit has issued a decision on the merits.

We disagree that the Fifth Circuit's recent stay decision in *Texas v. EPA* dictates the lawfulness or timeliness of this rulemaking. First, as the commenters have noted, the Fifth Circuit decision was not a final decision on the merits of our action on the Oklahoma and Texas regional haze SIPs; instead, it was a preliminary decision issued by a panel of Fifth Circuit judges reviewing motions to stay the EPA's FIP, otherwise referred to as a "motions panel." That panel expressly noted that its "determination of Petitioners' likelihood of success on the merits is for the purposes of the stay only and does not bind the merits panel."[42] Second, and more importantly, the Fifth Circuit's evaluation of the EPA's FIP was based on the existing visibility regulations at 40 CFR 51.308(d). In this rulemaking, we are promulgating new regulations at 40 CFR 51.308(f) that will govern the second and future implementation periods. Under CAA section 307(b), the D.C. Circuit Court of Appeals is the exclusive venue for judicial review of these regulations. Consequently, the preliminary views of another circuit on the lawfulness of a FIP issued in the first implementation period under our existing regulations at 40 CFR 51.308(d) are not germane to this rulemaking. Third, portions of the stay decision indicate a fundamental misunderstanding of aspects of the visibility program and the EPA's action on the Oklahoma and Texas regional haze SIPs. For example, the decision on several occasions conflated the BART and reasonable progress requirements of the RHR, even though the FIP solely concerned the

[42] *Id.* at *42 n.29.

latter.[43] Indeed, we explicitly delayed final action in promulgating a FIP to address the BART requirements for EGUs in Texas in light of the D.C. Circuit's decision to remand several of the Cross-State Air Pollution Rule's (CSAPR) emissions budgets.[44]

While the decision in *Texas v. EPA* does not dictate the outcome of this rulemaking, the decision has created some confusion regarding certain aspects of the visibility program, including (1) whether states can or must consider the four reasonable progress factors on a source-specific basis; (2) the scope of the consultation requirements; and (3) whether a state's long-term strategy can contain measures that cannot be fully implemented by the end of an implementation period. Consequently, we believe that it is appropriate to address each of these issues at this time to explain how it was treated under the existing regulations during the first implementation period and whether it will be treated any differently (and if so how) under the new regulations governing future implementation periods.

1. Source-Specific Analysis

In *Texas v. EPA*, the Fifth Circuit explained that neither the RHR nor the CAA requires a state to conduct a source-specific four-factor analysis.[45] Several commenters cited this aspect of the Fifth Circuit's decision to argue that the EPA's proposal could not require states to conduct source-specific four-factor analyses and that, while states could conduct such analyses at their discretion, a state's decision not to do so could not form the basis of the EPA's disapproval of a

---

[43] *See, e.g.*, *id.* at *8 (SIPs must "list the best available retrofit technology ('BART') that emission sources in the state will have to adopt to achieve the visibility goals"); *id.* at *9 ("BART is the only portion of the implementation plan that is enforced against emission sources in a state."); *id.* at *42 (asserting that "the BART requirements" are "the portion of the Final Rule imposing injury on Petitioners").
[44] 81 FR 301-02.
[45] *Id.* at *45-51.

SIP. Other commenters argued that proposed 40 CFR 51.308(f)(3)(ii) would unlawfully force states to conduct source-specific four-factor analyses if a state's RPGs provide for a slower rate of improvement in visibility than the URP. Several commenters asked us to clarify our position on these issues.

Neither the 1999 RHR nor the revised regulations in this rulemaking require states to conduct four-factor analyses on a source-specific basis. CAA section 169A(b)(2) requires states to include in their SIPs "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress." While these emission limits must apply to individual sources or units, section 169A(g)(1) does not explicitly require states to consider the four factors on a source-specific basis when determining what amount of emission reductions (and corresponding visibility improvement) constitutes "reasonable progress." Unlike section 169A(g)(2), which requires states to consider "any existing control technology in use at *the source*" and "the remaining useful life of *the source*" when determining BART, section 169A(g)(1) refers to the four factors more generally. For example, with respect to remaining useful life, section 169A(g)(1) refers not to "the source," but rather "any existing source subject to such requirements." Thus, the EPA has consistently interpreted the CAA to provide states with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on state policy preferences and the specific circumstances of each state. This is the case under the 1999 RHR and continues to be the case under these final revisions. Contrary to the arguments in some comments, 40 CFR 51.308(f)(3)(ii) explicitly refers to "sources *or groups of sources*." Similarly, 40 CFR 51.308(f)(2)(i) also refers to "major or minor stationary sources *or group of sources*, mobile sources, and area sources."

We also note that the stay decision in *Texas v. EPA* mistakenly indicated that the EPA disapproved the Texas SIP for failing to evaluate the four factors on a source-specific basis. As we explained in the January 2016 final rule, we disapproved Texas's four-factor analysis because the set of sources and controls that Texas analyzed was both over-inclusive and under-inclusive, not because the state failed to conduct a source-specific analysis.[46] Texas's analysis was over-inclusive because it included controls on sources that served only to increase total costs with little corresponding visibility benefit, and under-inclusive because it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements. While these final revisions to the RHR continue to provide states with considerable flexibility in evaluating the four reasonable-progress factors, we expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.

2. Interstate Consultation

In the *Texas v. EPA* stay decision, the Fifth Circuit explained that neither the RHR nor the CAA explicitly require upwind states to provide downwind states with source-specific emission control analyses.[47] Consistent with Congress's focus on interstate cooperation under

---

[46] 81 FR 313-14.
[47] *Id.* at *51-53.

section 169B, the 1999 RHR required states to consult with one another when developing their RPGs and long-term strategies, develop “coordinated emission management strategies” and document any disagreements regarding their goals and strategies.[48] We agree with the Fifth Circuit that the 1999 RHR did not require upwind states to provide downwind states with a specific type of four-factor analysis during the consultation process; the four-factor analysis that the upwind state did could be based on a source-specific or aggregate approach, for example. The consultation provisions were intended to foster and facilitate regional solutions to what is, by definition, a regional problem, not to mandate specific outcomes. The final revisions largely preserve the existing consultation provisions and similarly do not require upwind states to provide downwind states with any specific type of analysis, or vice versa. Nevertheless, to develop coordinated emission management strategies, each state must make decisions with respect to its own long-term strategy with knowledge of what other states are including in their strategies and why. In other words, states must exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies. To the extent that one state does not provide another other state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements.

3. Timing of Control Requirements

[48] 40 CFR 51.308(d)(1)(iv); (d)(3)(i).

Lastly, in *Texas v. EPA*, the Fifth Circuit's stay decision suggested that it was likely that the EPA had exceeded its statutory authority by imposing emission controls that go into effect after the end of the implementation period.[49] This preliminary assessment is incorrect for several reasons.

First, we note that the decision did not cite to a provision of the CAA to support the proposition that the EPA exceeded its statutory authority. Indeed, the CAA includes no such constraint. Two provisions are of particular relevance. Section 169A(b)(2)(B) requires SIPs to include "a long-term (ten to fifteen years) strategy for making reasonable progress toward meeting the national goal." The phrase "ten to fifteen years" is ambiguous. It could mean that the long-term strategy must be updated every 10 to 15 years or that the strategy must be fully implemented within 10 to 15 years. Even under the latter interpretation, courts have held that an agency does not lose authority to regulate when a mandatory deadline has passed; rather, the appropriate remedy is an order compelling agency action.[50] We therefore do not interpret this provision as restricting the authority of states or the EPA to include control measures in a SIP or FIP that cannot be fully implemented by the end of a regulatory implementation period or as relaxing their obligation to include such controls if they are otherwise necessary to make reasonable progress. To do so would create an inappropriate incentive for states to delay their SIP submittals in an effort to "run out the clock" on the EPA's authority to issue a corrective FIP.

---

[49] *Texas*, 2016 U.S. App. LEXIS 13058 at *53-57.
[50] *Oklahoma v. EPA*, 723 F.3d 1201, 1223-24 (10th Cir. 2013) (citing *Brock v. Pierce Cty.*, 476 U.S. 253, 260 (1986).

Also, section 169A(g)(1) requires states to consider “the time necessary for compliance” when determining what control measures are necessary to make reasonable progress. This phrase is also ambiguous. One possible interpretation of the phrase is that states need only consider control measures that can be implemented within a certain period of time. This interpretation is unreasonable, however, because it would allow states to forever forgo cost-effective but time-intensive emission reduction measures that could otherwise improve visibility, which would thwart Congress’s national goal. A more reasonable interpretation of the phrase is that states must consider the feasibility of the “schedules of compliance” referred to in section 169A(b)(2) when determining when the emission reductions necessary to make reasonable progress must be implemented. The structure of section 169A also lends support to this interpretation. When determining reasonable progress, states must consider three of the same factors that they consider when determining BART. The only unique reasonable progress factor relates to timing: “the time necessary for compliance.” Congress had no reason to include a timing factor for BART, however, because section 169A(b)(2)(A) already includes a requirement that BART must be installed and operated “as expeditiously as practicable,” which section 169A(g)(4) defines as no later than 5 years from the date of plan approval. With no similar requirement in section 169(b)(2), it is reasonable to interpret that Congress intended “the time necessary for compliance” factor to serve an analogous function to the “expeditiously as practicable” language, albeit with more discretion left to the states.

Second, we note that the Fifth Circuit appeared to misunderstand a provision in the 1999 RHR that it used to support its decision. Specifically, the stay decision stated:

> The Regional Haze Rule requires states to "consider . . . the emission reduction measures needed to achieve [the reasonable progress goal] *for the period covered*

> *by the implementation plan*," and to impose "enforceable emissions limitations, compliance schedules, and other measures, as necessary to achieve the reasonable progress goals." 40 C.F.R. § 51.308(d)(1)(i)(B), (d)(3) (emphasis added). The Regional Haze Rule provides that each implementation plan will cover a ten-year period; before the close of each ten-year period, the state must submit a comprehensive revision to cover the next ten-year period. 40 C.F.R. § 51.308(b), (f) (first implementation plan due December 2007; first "comprehensive periodic revision" due July 31, 2018, and every ten years thereafter). The emissions controls included in a state implementation plan, therefore, must be those designed to achieve the reasonable progress goal for the period covered by the plan. 40 C.F.R. § 51.308(d)(1)(i)(B).[51]

However, 40 CFR 51.308(d)(1)(i)(B) does not actually say that states must consider the emission reductions measures needed to achieve "the reasonable progress goal" for the period covered by the implementation plan. Instead, it requires states to "consider *the uniform rate of improvement in visibility* and the emission reduction measures needed to achieve *it* for the period covered by the implementation plan."[52] In essence, the provision requires a state to make a comparison between its chosen control set and the specific set of control measures that would be needed to achieve the URP by the end of the implementation period. The provision does not dictate the date by which all of the measures in a state's chosen control set must be implemented.

Third, the stay decision did not discuss the EPA's 2007 reasonable progress guidance, which specifically recognized that the time needed for full implementation of a control measure

[51] *Texas*, 2016 U.S. APP. LEXIS 13058 at *53-54.

[52] 40 CFR 51.308(d)(1)(i)(B) (emphases added).

might extend beyond the end of the implementation period. In such situations, the EPA stated that it may be appropriate for states to use the time necessary for compliance factor "to adjust the [RPG] to reflect the degree of improvement in visibility achievable within the period of the first SIP,"[53] which would prevent the state from falling short of its goal. The 2007 guidance did not state that the CAA or the 1999 RHR prohibited states from requiring the control measure.

In the proposal for this rulemaking, which was promulgated before the Fifth Circuit's stay decision, we did not address this issue. At that time, we thought that it was clear that neither states nor the EPA lose the authority to require emissions limits or other measures that are necessary to make reasonable progress if those limits or measures cannot be fully implemented by the end of the implementation period and incorporated into the RPGs. For the reasons provided previously, we continue to believe that this is the case.

Therefore, we are modifying 40 CFR 51.308(f)(2)(i) to explicitly provide that, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period. As discussed previously, the state should instead consider that fact in determining the appropriate compliance deadline for the measure. Of course, any emission reductions that will not occur until after the end of the implementation period should not be reflected in the RPGs.

In addition, to avoid any future confusion with respect to this issue, we are making a small modification to 40 CFR 51.308(f)(3)(i) in these final revisions. This final provision now reads:

[53] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, revised, at 5-2 (June 1, 2007).

> A State in which a mandatory Class I Federal area is located must establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of *those* enforceable emissions limitations, compliance schedules, and other measures required under paragraph (f)(2) *that can be fully implemented by the end of the applicable implementation period*, as well as the implementation of other requirements of the CAA.

This modification makes it clear that a state's long-term strategy can include emission limits and measures beyond those reflected in the state's RPGs. The RPGs are unenforceable tracking metrics. They are not meant to dictate or limit the content of a state's long-term strategy for making reasonable progress towards Congress's national goal. This change is also consistent with our actions promulgating FIPs near the end of the first implementation period, which by necessity included reasonable progress emission limits with compliance deadlines after 2018.[54]

B. Cooperative Federalism

Some commenters invoked principles of cooperative federalism to argue that the proposed revisions were too prescriptive and thus undermined the discretion afforded to states by the CAA. As support for this argument, the commenters pointed almost exclusively to the Fifth Circuit's stay decision in *Texas v. EPA*, discussed previously, in which a motions panel of the Fifth Circuit described EPA's role in reviewing SIPs as "ministerial."[55] Commenters also suggest the proposed revisions are inconsistent with the principles announced in *American Corn Growers Association v. EPA*, 291 F.3d 1 (D.C. Cir. 2002) ("Corn Growers").

[54] 81 FR 296 (January 5, 2016) (Texas); 81 FR 68319 (October 4, 2016) (Arkansas).
[55] *Texas*, 206 U.S. App. LEXIS 13058 at *5.

As a preliminary matter, the commenters' reliance on *Texas v. EPA* is misplaced. The view expressed in the stay decision, that the EPA has only a "ministerial function" in reviewing SIPs, is at odds with the great majority of courts that have considered this issue in the context of the regional haze program. Under the principles of cooperative federalism, the CAA vests state air agencies with substantial discretion as to how to achieve Congress's air-quality goals and standards, but states exercise this authority with federal oversight. As the Tenth Circuit explained in *Oklahoma v. EPA*, "the EPA reviews all SIPs to ensure that they comply with the [CAA]," and "[t]he EPA may not approve any plan that 'would interfere with any applicable requirement' of [the Act]."[56] Relying on *Oklahoma*, the Eighth Circuit in *North Dakota v. EPA* held that the "EPA is left with more than the ministerial task of routinely approving SIP submissions,"[57] and that the "EPA's review of a SIP extends not only to whether the state considered the necessary factors in its determination, but also to whether the determination is one that is reasonably moored to the CAA's provisions."[58] Similarly, in *Arizona v. EPA*, the Ninth Circuit held that the "EPA is not limited to the 'ministerial' role of verifying whether a determination was made; it must 'review the substantive content of the . . . determination,'"[59] and that the "EPA has a *substantive* role in deciding whether state SIPs are compliant with the Act and its implementing regulations."[60] In accord with these principles, the Third Circuit recently remanded the EPA's approval of a state's regional haze SIP where the EPA deferred too readily to state conclusions

[56] *Oklahoma v. EPA*, 723 F.3d 1201, 1204 (10th Cir. 2013).
[57] *North Dakota v. EPA*, 730 F.3d 750, 761 (8th Cir. 2013).
[58] *Id.* at 766.
[59] *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).
[60] *Id.* at 532 (emphasis in original).

without providing a sufficient explanation for overlooking problems in the SIP.[61] Thus, the view expressed by the Fifth Circuit motions panel in the stay decision is an outlier.

More importantly, however, the situation in *Texas v. EPA* is inapposite to the situation here. In *Texas*, we partially disapproved an individual state's implementation plan and promulgated a FIP to fill the gap. In this rulemaking, we are not expressing views on any state's implementation plan, so it is simply premature to suggest that we are affording insufficient deference to state choices. Rather, we are promulgating revisions to the existing visibility regulations that will guide future SIP development. In 1977, Congress expressly required the EPA to promulgate regulations "to assure (A) reasonable progress toward meeting the national goal . . . and (B) compliance with the requirements of [section 169A]."[62] Congress also required the EPA's regulations to "provide guidelines to the States"[63] regarding "methods for identifying, characterizing, determining, quantifying, and measuring visibility impairment;"[64] "modeling techniques for determining the extent to which manmade air pollution may reasonably be anticipated to cause or contribute to such impairment;"[65] and "methods for preventing and remedying such manmade air pollution and resulting visibility impairment."[66] In 1990, Congress reiterated this statutory obligation, tasking the EPA again with carrying out its "regulatory responsibilities under [section 169A], including criteria for measuring 'reasonable progress' toward the national goal."[67]

---

[61] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 167 (3d Cir. 2015).
[62] CAA section 169A(b).
[63] CAA section 169A(b)(1).
[64] CAA section 169A(a)(3)(A).
[65] CAA section 169A(a)(3)(B).
[66] CAA section 169A(a)(3)(C).
[67] CAA section 169B(e)(1).

These final revisions to the 1999 RHR and 1980 reasonably attributable visibility impairment regulations are fully consistent with this extensive grant of rulemaking authority. The revisions will ensure that the steady environmental progress achieved during the first implementation period continues, while streamlining several administrative aspects of the program to reduce burdens on states. The revisions require states to consider certain factors and provide certain information as they develop their regional haze SIPs, but they do not mandate specific outcomes. Where applicable, the revisions also provide states with significant flexibility to take state-specific facts and circumstances into account when developing their long-term strategies.[68] Thus, contrary to the commenters' assertions, the final revisions are fully consistent with the CAA's cooperative-federalism framework and the decision in *Corn Growers*, which addressed EPA's authority to require states to consider the visibility benefits of BART controls in a specific fashion, a set of facts not present in this rulemaking, is not on point.

C. Clarifications to Reflect the EPA's Long-Standing Interpretation of the Relationship Between Long-Term Strategies and Reasonable Progress Goals.

1. Summary of Proposal

Under the 1999 RHR, states were required to revise their regional haze SIPs every 10 years by evaluating and reassessing all of the elements required under 40 CFR 51.308(d).[69] Over the course of the first implementation period, however, we realized that some of the requirements in 40 CFR 51.308(d) were creating confusion regarding the relationship between RPGs and the long-term strategy and the respective obligations of upwind and downwind states. We discussed

---

[68] *See, e.g.*, 81 FR at 26954/1 (explaining that states have the flexibility to justify and use values for natural visibility conditions that include anthropogenic international emissions).

[69] 40 CFR 51.308(f).

this issue at length in our December 14, 2014, proposed action on the Texas and Oklahoma regional haze SIPs,[70] and incorporated that discussion by reference in the proposal for this rulemaking.[71]

For example, under 40 CFR 51.308(d), states were required to (1) develop RPGs, (2) calculate baseline and natural visibility conditions, (3) establish long-term strategies and (4) adopt monitoring strategies and other measures to track future progress and ensure compliance. The sequencing of these requirements in the rule text was problematic because it did not accord with the way the planning process works in practice. For example, states must calculate baseline and natural visibility conditions before they can compare their RPGs to the URP. Similarly, states must evaluate the control measures that are necessary to make reasonable progress using the four factors and develop their long-term strategies before they can predict future emission reductions and conduct the regional-scale modeling used to establish RPGs.

Similarly, problematic was the confusing way in which 40 CFR 51.308(d) addressed the obligations of upwind and downwind states. Under 40 CFR 51.308(d)(1)(i)(A), downwind states were explicitly required to consider the four factors when developing their RPGs. Upwind states, on the other hand, were implicitly required to consider the four factors only when developing their long-term strategies. Section 40 CFR 51.308(d)(3)(iii) required states to "document the technical basis, including modeling, monitoring and emissions information, on which the State is relying *to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects*." As we explained in our December 14, 2014, proposed action on the Texas and Oklahoma regional haze SIPs, the CAA

[70] 79 FR 74823-30 (December 14, 2014).
[71] 81 FR 26949, 26952.

requires states to determine reasonable progress by considering the four factors, so the determination of the proper apportionment of emission reductions necessarily required a state to evaluate the four factors in reaching its decision. This structure made little sense because both upwind and downwind states need to conduct their four-factor analyses, determine the proper apportionment of emission reduction obligations, and develop their long-term strategies before the downwind state will have sufficient information to establish RPGs.

Recognizing that the sequence and structure of the existing regulations was confusing, we proposed to amend 40 CFR 51.308(f), which governs periodic SIP revisions for future implementation periods, to codify our long-standing interpretation of the way in which the existing regulations were intended to operate. Specifically, we proposed to eliminate the cross-reference in 40 CFR 51.308(f) to 40 CFR 51.308(d) and to adopt new regulatory language that tracked the actual planning sequence, while clarifying the obligations of upwind and downwind states.[72] Under the proposal, states would (1) calculate baseline, current and natural visibility conditions, progress to date and the URP; (2) develop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress; (3) conduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line;[73] and (4) adopt a monitoring strategy and other measures to track future progress and ensure compliance.

2. Comments and Responses

---

[72] 81 FR 26952.

[73] This step applies only to downwind states that have mandatory Class I Federal areas.

In response to our proposed structural revisions to 40 CFR 51.308(f), we received a number of significant comments. Some commenters contended that the proposed revisions were contrary to the structure and plain language of the CAA. They explained the position that states must first make a "determination" as to what constitutes "reasonable progress" by analyzing the four statutory factors on a source-category basis. Then, only after "reasonable progress" is quantified as a benchmark or goal do states have to consider what emission limits, schedules of compliance and other measures at individual sources are actually necessary to make reasonable progress. The commenters further explained that this reading of the statute was supported by the current regulations, the preamble to the 1999 RHR and the EPA's prior guidance. Based on their reading, these commenters concluded that proposed 40 CFR 51.308(f)(2), which would govern long-term strategies, and proposed 40 CFR 51.308(f)(3), which would govern RPGs, were contrary to the CAA because states must first determine reasonable progress independently from the development of the long-term strategy, not the other way around.

We disagree. Our proposed structural revisions to 40 CFR 51.308(f) are consistent with the CAA. Section 169A(b)(2) requires states to submit SIP revisions that contain "emission limits, schedules of compliance and other measures as necessary to make reasonable progress toward meeting the national goal" and "a long-term (ten to fifteen years) strategy for making reasonable progress." Section 169A(g)(1) states that, in determining reasonable progress, states must consider four factors: "the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." Under 40 CFR 51.308(f)(2), both as proposed and as we are finalizing it, states must similarly submit a "long-term strategy" that includes "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress," and determine those limits, schedules, and measures by considering the four statutory factors.

We disagree that the CAA requires EPA's regulations to allow states to calculate the visibility improvement that represents "reasonable progress" prior to or independently from the analysis of control measures. The commenters do not explain how states could consider costs, time schedules, energy and environmental impacts or the remaining useful lives of sources other than by assessing the potential impacts of control measures on those sources. Indeed, use of the terms "compliance" and "subject to such requirements" in section 169A(g)(1) strongly indicates that Congress intended the relevant determination to be the requirements with which sources would have to comply in order to satisfy the CAA's reasonable progress mandate. Moreover, the reasonable progress factors share obvious similarities with the BART factors, which are indisputably used to determine appropriate control measures for sources.[74]

Finally, we note that RPGs are not a concept that is included in the CAA itself. Rather, they are a regulatory construct that we developed to satisfy a separate statutory mandate in section 169B(e)(1), which required our regulations to include "criteria for measuring 'reasonable progress' toward the national goal."[75] Under 40 CFR 51.308(f)(3)(ii), RPGs continue to serve this important analytical function. They measure the progress that is projected to be achieved by

---

[74] *Compare* CAA section 169A(g)(1) *with* CAA section 169A(g)(2).

[75] *See* 64 FR 35731 ("The final rule calls for States to establish 'reasonable progress goals,' expressed in deciviews, for each Class I area for the purpose of improving visibility on the haziest days and not allowing degradation on the clearest days over the period of each implementation plan or revision. The EPA believes that requiring States to establish such goals is consistent with section 169A of the CAA, which gives EPA broad authority to establish regulations to 'ensure reasonable progress,' and with section 169B of the CAA, which calls for EPA to establish 'criteria for measuring reasonable progress' toward the national goal.").

the control measures states have determined are necessary to make reasonable progress based on a four-factor analysis. Consistent with the 1999 RHR, the RPGs are unenforceable,[76] but they create a benchmark that allows for analytical comparisons to the URP[77] and mid-implementation-period course corrections if necessary.[78]

Other commenters stated that the proposed revisions to 40 CFR 51.308(f) were significant and unexplained departures from the EPA's prevailing interpretation of the reasonable progress factors and long-term strategy during the first implementation period. Several commenters contended that the revisions constituted an arbitrary and capricious change of position under the Supreme Court's recent decision in *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117 (2016). For example, one commenter contended that it was paradoxical for the long-term strategy to include the measures necessary to achieve the RPGs, while the RPGs were the predicted visibility outcome of implementing the emission controls in the long-term strategy. The commenter explained that this was inconsistent with the 1999 RHR, which made no mention of RPGs being set based on the predicted visibility improvement resulting from emission controls.

Another commenter contended that the EPA's proposed approach puts the cart before the horse because it does not allow states and RPOs to set visibility targets and then select the appropriate emission reduction measures to reach those targets. This would result in inefficiencies, according to the commenter, because states may have to secure additional emission reductions if their chosen strategies result in RPGs that fall short of the URP. The

[76] *Compare* 40 CFR 51.308(f)(3)(iii) *with* 40 CFR 51.308(d)(v).
[77] *Compare* 40 CFR 51.308(f)(3)(ii) *with* 40 CFR 51.308(d)(1)(ii).
[78] 40 CFR 51.308(g)(7), (h).

commenter explained that states would need more guidance regarding what types of sources and source categories to consider when seeking emission reductions. The commenter requested that the EPA develop a more logical process whereby states and RPOs would first develop visibility goals, allocate those goals among the states and then give states latitude to identify and assure emission reductions to achieve those visibility goals by using the four factors.

We disagree with these comments. They reflect a misunderstanding of the regional haze planning process generally followed by states. During the first implementation period, the RPOs conducted the regional-scale modeling used to establish their member states' RPGs. To conduct this modeling, the RPOs relied on 2018 emissions projections that reflected future application of reasonable controls for sources, including existing federal and state measures (the Clean Air Interstate Rule (CAIR), mobile source measures, etc.), anticipated BART controls and anticipated reasonable progress measures. The proposed and final revisions to 40 CFR 51.308(f) are fully consistent with this process. Under 40 CFR 51.308(f)(ii), states must develop their long-term strategies by identifying reasonable progress measures using the four factors and engaging in interstate consultation. Once their strategies have been developed, states with Class I areas must establish RPGs that reflect existing federal and state measures (the CSAPR, the Mercury and Air Toxics Standards, BART, mobile source measures, etc.) and the reasonable progress measures in the long-term strategy.

In contrast, the commenters have proposed a process in which states would either model their RPGs without fully developed emissions information or select their goals arbitrarily without any modeling at all. We rejected a similar approach in the 1999 RHR. In the 1997 proposal for the RHR, we proposed to establish presumptive reasonable progress targets of 1.0 deciview of improvement for the most impaired days and no degradation for the least impaired days and to require states to develop emission reduction strategies to achieve the reasonable progress targets.[79] In the 1999 RHR, we revised the proposal to eliminate the presumptive targets and instead required states "to determine the rate of progress for remedying existing impairment that is reasonable, taking into consideration the statutory factors."[80] Importantly, we explained that, "[i]n considering whether reasonable progress will continue to be maintained, States will need to consider during each new SIP revision cycle whether additional control measures for improving visibility may be needed to make reasonable progress based on the statutory factors."[81] Thus, the 1999 RHR was clear that states must determine what control measures are necessary to make reasonable progress by considering the four factors and then use this information to determine the rate of progress that is reasonable for each mandatory Class I Federal area.

In 2007, we provided guidance to the states on setting RPGs. There, we explained that the guidance's discussion of the four factors was "largely aimed at helping States apply these factors *in considering measures for point sources*,"[82] but that the factors could potentially be applied to sources other than point sources as well. We also described the intricate relationship between RPGs, BART, and the long-term strategy:

> The RPGs, the long-term strategy, and BART (or alternative measures in lieu of BART) are the three main elements of the regional haze SIPs that States are required to submit by December 17, 2007. The long-term strategy and BART emissions limitations or other alternative measures, including cap-and-trade

[79] 62 FR 41146-47 (July 31, 1997).
[80] 64 FR 35731 (July 1, 1999).
[81] *Id.* at 35733.
[82] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, at 1-3 (2007) (emphasis added).

programs or other economic incentive approaches, are inherently related to the RPG. The long-term strategy is the compilation of "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the [RPGs]," and is the means through which the State ensures that its RPG will be met. BART emissions limits (or alternative measures in lieu of BART, such as the Clean Air Interstate Rule (CAIR)) are one set of measures that must be included in the SIP to ensure that an area makes reasonable progress toward the national goal, and the visibility improvement resulting from BART (or a BART alternative) is included in the development of the RPG.[83]

We note that the discussion previously refers to the long-term strategy as including the measures "necessary to achieve the RPG," and that several provisions in the 1999 RHR were worded similarly.[84] We believe this type of language may have caused confusion among some of the commenters. This language does not mean that we intended states to develop their RPGs first and later adopt measures in the long-term strategy to achieve those RPGs. Rather, it merely acknowledges the fact that, because we intended states to develop their RPGs by modeling, among other things, the measures in the long-term strategy, the measures in the strategy are necessary to achieve the RPGs. For example, BART is one of the measures in the long-term strategy, and the discussion previously clearly states that "the visibility improvement resulting from BART (or a BART alternative) *is included in the development of the RPG*." We proposed the structural revisions to 40 CFR 51.308(f) in part to eliminate this cart-before-the-horse ambiguity.

[83] *Id.* at *1-4*.
[84] *See, e.g.*, 40 CFR sections 51.308(d)(3), (d)(3)(ii), (d)(3)(v)(C).

Later, the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states "[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area."[85] Second, we recommended that states "[i]dentify the control measures and associated emission reductions that are expected to result from compliance with existing rules *and* other available measures for the sources and source categories that contribute significantly to visibility impairment."[86] Third, and most importantly, we recommended that states "[d]etermine what additional control measures would be reasonable based on the statutory factors and other relevant factors for the sources and/or source categories you have identified."[87] Finally, we recommended that states "[e]stimate through the use of air quality models the improvement in visibility that would result from implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress."[88] In sum, "[t]he improvement in visibility resulting from implementation of the measures you have found to be reasonable . . . is the amount of progress that represents your RPG."[89] This is the process that states used during the first implementation period, *see* the RTC at 2.2.1.2.6 for examples, and it is the same process that the states must follow under the final revisions to 40 CFR 51.308(f).

While the guidance went on to note that states could attempt to "back out" the measures necessary to achieve the URP by modeling first and then considering the four factors to select appropriate measures,[90] few if any states chose this approach, likely because it was a more

---

[85] *Id.* at 203.
[86] *Id.* (emphasis in the original).
[87] *Id.*
[88] *Id.*
[89] *Id.* at 2-4 (emphasis added).
[90] *Id.* at 2-3 to 2-4.

complicated way to achieve the same result as the recommended approach. Under either approach, states still had to use the four factors to justify whether the control measures necessary to achieve the URP were reasonable, whether achieving the URP was unreasonable and some of lesser set of measures was reasonable, or whether additional measures were reasonable. Moreover, the "back out" approach specified a concrete visibility target as its basis: the visibility that would be achieved by the URP at the end of the implementation period. The approach would be arbitrary and unworkable as a step in making the justifications just mentioned if the visibility target were chosen at random, as some commenters have requested. In sum, the EPA's proposed structural revisions are completely consistent with the 1999 RHR, our 2007 guidance and the planning process actually used by states during the first implementation period. For this reason, the Supreme Court's decision in *Encino Motorcars* is inapplicable.

Another commenter contended that the EPA's proposed revisions failed to include a necessary step where states evaluate the control measures identified as necessary to make reasonable progress in light of the RPGs themselves. This commenter requested a mechanism whereby a state could determine that some of the initially evaluated control measures were unnecessary in light of the RPGs themselves. In particular, this commenter suggested that a state should be able to reject "costly" control measures if (1) the RPG for the most impaired days is on or below the URP line or (2) the RPGs are not "meaningfully" different than current visibility conditions.

We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress.

In regards to the commenter's first suggestion, if a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line. The URP is not a safe harbor, however, and states may not subsequently reject control measures that they have already determined are reasonable. If a state's RPG for the most impaired days is above the URP line, then the state has an additional analytical obligation to ensure that no reasonable controls were left off the table.

The commenter's second suggestion, that states should be able to reject "costly" control measures if the RPG for the most impaired days is not "meaningfully" different than current visibility conditions, is counterintuitive and at odds with the purpose of the visibility program. In this situation, the state should take a second look to see whether more effective controls or additional measures are available and reasonable. Whether the state takes this second look or not, it may not abandon the controls it has already determined are reasonable based on the four factors. Regional haze is visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it would not be appropriate for a state to reject a control measure (or measures) because its effect on the RPG is subjectively assessed as not "meaningful." Also, for Class I areas where visibility conditions are considerably worse than natural conditions because of continuing anthropogenic impairment from numerous sources, the logarithmic nature of the deciview index makes the effect of a control measure on the value of the RPG less than its effect would be if visibility conditions at the Class I area were better. Thus, if a state could reject a control measure based on its individual effect on the RPG, the state would be more likely to reject those measures that are necessary to make reasonable progress at the dirtiest Class I areas, which would thwart Congress' national goal.

One commenter contended that the proposed revisions would lead to disagreements among states because states might set different RPGs instead of working jointly toward the downwind state's goals. We disagree. Only downwind states set RPGs for their mandatory Class I Federal areas, so there is no situation in which there would be different goals for the same area.

Another commenter contended that the proposed revisions would force states to require controls even where visibility at a Class I area is already equivalent to or better than the visibility that represents the URP at the end of the implementation period. We agree that some states may end up establishing RPGs that exceed the URP, but as we explained previously in this document, the URP was never intended to be a safe harbor. In the 1999 RHR, we explained that "[i]f the State determines that the amount of progress identified through the analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy."[91] This approach is consistent with and advances the ultimate goal of section 169A: remedying existing and preventing future visibility impairment. Congress required the EPA to promulgate regulations requiring reasonable progress toward that goal, and it would be antithetical to allow states to avoid implementing reasonable measures until and unless that goal is achieved.

Other commenters were supportive of the proposed structural revisions intended to clarify the relationship between RPGs and long-term strategies. They explained that by reorienting these provisions to reflect the EPA's long-standing interpretation, the EPA was providing a clearer blueprint for states to follow in future implementation periods. These commenters also provided specific suggestions for how the EPA could further revise the proposed regulatory text for 40 CFR 51.308(f). Among other things, these commenters requested that the EPA include language in the regulations that would make it clear that a state's long-term strategy can include emission limits and other measures that cannot be installed by the end of an implementation period. As discussed earlier in Section IV.A of this document, we are modifying the language in 40 CFR 51.308(f)(2(i) and 51.308(f)(3)(i) to make this point clear. We have reviewed the other suggestions made by these commenters and do not believe that they are necessary, as discussed more fully in the RTC document available in the docket for this rulemaking.

We also received several comments regarding the obligations of upwind and downwind states. Some commenters supported the revisions that were intended to clarify that all states must conduct a four-factor analysis to determine what control measures are necessary to make

[91] 64 FR 35732.

reasonable progress at each mandatory Class I Federal area affected by emissions from the state. They explained that any other interpretation of the CAA's requirements would allow an upwind state to continue impairing downwind visibility without consequence, regardless of whether there were reasonable, cost-effective measures that would improve downwind visibility. Other commenters argued that upwind states should not have the same obligations as downwind states. One commenter asserted that, under the proposal, all states would be subject to the RHR for the very first time, regardless of whether they have a mandatory Class I Federal area or not. Another commenter contended that requiring upwind states to conduct four-factor analyses for downwind Class I areas was a new requirement that was not part of the 1999 RHR. This commenter acknowledged that upwind states must address downwind Class I areas where their emissions "may reasonably be anticipated to cause or contribute to any impairment of visibility" at the downwind area, but suggested that the proposed revisions use the language "may affect" instead. This commenter stated that the EPA's proposal did not define or quantify what the term "may affect" means.

Section 169A(b)(2) states that the EPA's regulations must:

> require each applicable implementation plan for a State in which any [mandatory Class I Federal] area . . . is located (or a for a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area) to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal.

Section 169A(g)(1) thus requires states to determine the measures necessary to make reasonable progress by considering the four factors, while section 169A(a)(1) defines Congress's national goal as preventing future and remedying existing anthropogenic visibility impairment in all Class

I areas. Thus, Congress was clear that both downwind states (i.e., "a State in which any [mandatory Class I Federal] area . . . is located) and upwind states (i.e., "a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area") must revise their SIPs to include measures that will make reasonable progress at all affected Class I areas. Congress was also clear that states must determine the necessary measures and rate of progress that are reasonable by considering the four factors. Our proposed revisions to 40 CFR 51.308(f)(2) are in accord with this congressional mandate.

The commenter who suggested that our proposed revisions are expanding the scope of the RHR to all states for the first time is incorrect. The 1999 RHR applies to all states,[92] and all states submitted regional haze SIPs (or asked the EPA to promulgate a regional haze FIP on its behalf) during the first implementation period. As discussed later in this preamble, we are expanding the scope of the 1980 reasonably attributable visibility impairment regulations to all states for the first time, but the new reasonably attributable visibility impairment provisions only require state action upon receipt of a certification by a FLM. Historically, there have been very few FLM certifications requesting states to assess controls for a particular source or small group of sources.

Finally, we note that the language "may affect" in 40 CFR 51.308(f)(2) was adapted from the 1999 RHR, which used the same term.[93] On July 8, 2016, we released draft guidance that discusses how states can determine which Class I areas they "may affect" and therefore must consider when selecting sources for inclusion in a four-factor analysis.[94] The draft guidance

---

[92] 40 CFR 51.300(b)(1)(i).
[93] *See* 40 CFR 51.308(d)(3).
[94] 81 FR 44608 (July 8, 2016).

discusses various approaches that states used during the first implementation period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt "a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas."[95] We plan to finalize the draft guidance in the near future.

We also received comments on the proposed interstate consultation provisions in 40 CFR 51.308(f). A few commenters inquired whether proposed 40 CFR 51.308(f)(2)(iii)[96] would affect a substantive change from the existing consultation provisions in 40 CFR 51.308(d). One commenter stated that proposed 40 CFR 51.308(f)(2)(ii) would apparently require states to consider how other states calculated the URP, adopted emission reduction measures for sources and adopted any additional measures that may be needed to address state contributions. This commenter also argued that proposed 40 CFR 51.308(f)(2)(iii) would incentivize states not to agree with other states on coordinated emission management strategies because an agreement would create an enforceable obligation against the state. Another commenter stated that the EPA would need to coordinate and mediate interstate consultations in order for them to prove successful.

With one exception, we did not intend the proposed interstate consultation provisions to affect a substantive change from the existing provisions in the 1999 RHR. Under the proposed provisions, as under the 1999 RHR, states must consult to develop coordinated emission

---

[95] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, at 57-58 (2016).
[96] As explained later in this document, the final rule includes a consolidation and resulting renumbering of some of the proposed provisions of 40 CFR 51.308(f)(2). This discussion refers specifically to either proposed or final section numbers to avoid confusion.

management strategies, demonstrate that their SIPs contain all agreed-upon emission reduction measures, and document disagreements so that the EPA can properly evaluate whether each state's implementation plan provides for reasonable progress toward the national goal. We also proposed a new requirement, in 40 CFR 51.308(f)(2)(ii), that states must consider the control strategies being adopted by other states when conducting their own four-factor analyses. The purpose of this provision was to ensure that if one state had identified a control measure as being reasonable for a source or group of sources to improve visibility at a Class I area, then other states that affect that Class I area would be required to consider that control measure for their own sources, to the extent that the sources share similar characteristics. However, in reviewing proposed 40 CFR 51.308(f)(2)(ii), we realized that it contains extraneous language that has led to confusion among some of the commenters. We discuss this issue in more depth, and other changes being made to the consultation provisions, in the following section.

In regard to the commenter's concern that the consultation provisions will incentivize states to avoid entering into agreements with each other to avoid enforceable obligations, we disagree. States largely worked cooperatively to develop coordinated emission management strategies during the first implementation period, and we expect that they will do so again. If a state believes that additional controls from sources in another state or states are necessary to make reasonable progress at a Class I area, then the state should document the disagreement to assist the EPA in determining whether the other state's SIP is inadequate. Moreover, even if states were to avoid entering into agreements for the purpose of avoiding enforceable obligations under 40 CFR 51.308(f)(iii), this would not absolve the states of their independent obligation to include in their SIPs enforceable emission limits and other measures that are necessary to make reasonable progress at all affected Class I areas, as determined by considering the four factors.

Finally, we do not believe that the EPA needs to coordinate or mediate interstate consultations. During the first implementation period, states consulted one-on-one and through the RPO process without EPA oversight, and we expect this process to work going forward as well.

3. Final Rule

We are finalizing the revisions to 40 CFR 51.308(f) that were intended to clarify the relationship between RPGs and long-term strategies and the obligations of upwind and downwind states largely as proposed. However, we are making several changes to the provisions in 40 CFR 51.308(f)(2) governing long-term strategies to simplify these provisions, enhance clarity and eliminate superfluous regulatory text.

In 40 CFR 51.308(f)(2), we are revising the requirement that states must include in their long-term strategies "the enforceable emissions limitations, compliance schedules, and other measures that are necessary to achieve reasonable progress" to read "make reasonable progress" instead. This change is to maintain consistency with the language in CAA section 169A(b)(2).

In 40 CFR 51.308(f)(2)(i), we are making two minor changes. First, we are revising the beginning of the first sentence to read, "[t]he State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering" the four factors. We believe that this formulation is clearer than the language in the proposal and more consistent with the language of the CAA. Second, we are revising the second sentence, and splitting it into two separate sentences, to make it clear that states must consider anthropogenic sources of visibility impairment when conducting their four-factor analyses, not natural sources, and that anthropogenic sources can include mobile and area sources in addition to major and minor stationary sources. As mentioned earlier, we are also adding a sentence to 40 CFR

51.308(f)(2)(i) regarding the consideration of emission controls that cannot reasonably be installed prior to the end of the implementation period.

We are removing proposed 40 CFR 51.308(f)(2)(ii) in these final revisions, which required states to consider the URP, the emission reduction measures identified under 40 CFR 51.308(f)(2)(i), and measures being adopted by contributing states under 40 CFR 51.308(f)(2)(iii) when developing their long-term strategies. States are already required to consider the URP under 40 CFR 51.308(f)(3)(ii) when establishing their RPGs. Moreover, it is duplicative to require states to consider the emission reduction measures identified under 40 CFR 51.308(f)(2)(i) a second time. As discussed in the following paragraph, we are moving the third requirement in proposed 40 CFR 51.308(f)(2)(ii) to the interstate consultation provisions.

We are changing proposed 40 CFR 51.308(f)(2)(iii), regarding interstate consultations, to be 40 CFR 51.308(f)(2)(ii) and making several changes. First, we are removing the distinction between contributing states and states affected by contributing states because the substance of the two provisions was essentially the same. The final revisions include a single provision requiring each state to consult with the other states that are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area to develop coordinated emission management strategies. Identification of the other states should occur as part of a regional planning process. Second, we are revising the language that required states to obtain either their "share of the emission reductions needed to provide for reasonable progress" or "all measures needed to achieve its apportionment of emission reduction obligations" depending on whether the state was a contributing state or a state affected by contributing states. Most states are both contributing states and states affected by contributing states, so these variations in wording could be viewed as creating two distinct obligations. Now, each state must demonstrate that it has included in its long-term strategy "all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement." Third, as discussed previously, we have moved the requirement that states consider the emission reduction measures other states have identified as being necessary to make reasonable progress from proposed 40 CFR 51.308(f)(2)(ii), which accordingly has been eliminated, to the interstate consultation provisions (now numbered as 40 CFR 51.308(f)(2)(ii)) because it is a more logical place for it. We have also revised the wording of this provision to eliminate the ambiguity in the proposed language noted by commenters regarding "additional measures being adopted" by other states. Under this provision, states must consider whether the emission reduction measures other states have identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area. This consideration is appropriate especially when the sources are of a similar type and have similar emissions profiles and visibility impacts.

We are changing proposed 40 CFR 51.308(f)(2)(iv), regarding documentation requirements, to be 40 CFR 51.308(f)(2)(iii) and making a few minor changes. First, we are revising the first sentence to require the states to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects." The proposed language referred to "information on the factors listed in (f)(2)(i) and modeling, monitoring, and emissions information," but we believe this language was confusing because it suggested that information on the four factors was something distinct from modeling, monitoring and emissions information. The purpose of this provision is to require states to document all of the information on which they rely to develop their long-term strategies, which will primarily be information used to conduct the four-factor analysis. Therefore, in addition to modeling, monitoring and emissions information, we are making it explicit that states must also submit the cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources.

We are removing proposed 40 CFR 51.308(f)(2)(v), which required states to identify the anthropogenic sources of visibility impairment analyzed using the four factors and the criteria used to select sources for analysis, because 40 CFR 51.308(f)(2)(i) as finalized already includes these requirements.

Finally, we are changing proposed 40 CFR 51.308(f)(2)(vi) to be 40 CFR 51.308(f)(2)(iv) and making a few changes. We are revising the first sentence of this provision to clarify that the enumerated factors are additional to the factors states must consider in 40 CFR 51.308(f)(2)(i). We are also removing proposed 40 CFR 51.308(f)(2)(vi)(C) and (F) because they are duplicative requirements. These provisions required states to consider the emission limitations and schedules for compliance to achieve the RPG and the enforceability of emission limitations and control measures. Section 40 CFR 51.308(f)(2) already requires states to include enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress in their long-term strategies. Section IV.G of this document discusses revisions we are making to the additional factor regarding basic smoke management practices and smoke management programs.

D. Other Clarifications and Changes to Requirements for Periodic Comprehensive Revisions of Implementation Plans

The following clarifications and changes were also proposed to be included in the revised 40 CFR 51.308(f). A summary of each proposed clarifying change, a synopsis of the final rule, and a discussion of comments received and EPA's responses are given later.

The URP line starts at 2000-2004, for every implementation period.

1. Summary of Proposal

The 1999 RHR's text of 40 CFR 51.308(d)(1)(i)(B) contains a discussion of how states must analyze and determine "the rate of progress needed to attain natural visibility conditions by the year 2064." This rate has commonly been called the "uniform rate of progress" or URP as well as "the glidepath." The 1999 RHR's text of 40 CFR 51.308(f), which indicates that states must evaluate and reassess all elements required by 40 CFR 51.308(d), requires states to evaluate and reassess the URP in the second and subsequent implementation periods. We explained in the proposal that 40 CFR 51.308(d) is not perfectly clear as to whether the URP line for the second or later implementation periods must always start in the baseline period of 2000-2004, or whether the state must (or may) recalculate the starting point of the URP line based on data from the most recent 5-year period during each successive regional haze SIP revision. [97] We also explained that although the regulations make clear that the endpoint of the URP line should be set based on attainment of the natural visibility condition for the 20 percent most impaired days in 2064, the 1999 RHR does not specify an exact date in 2064 for this element.

To ensure consistent understanding of how the URP analysis must be done, the EPA proposed rule revisions in 40 CFR 51.308(f)(1)(i) and (vi) that would make it explicit that in

[97] The preamble to the 1999 RHR provides an example explaining how a state would determine the 2028 point on the URP line. 64 FR at 35746, n. 113. In this example, the URP line for the second implementation period starts at 2000-2004.

every implementation period, the URP line for each Class I area is to be drawn starting on December 31, 2004, at the value of the 2000-2004 baseline visibility conditions for the 20 percent most impaired days, and ending at the value of natural visibility conditions on December 31, 2064. Specifying that the 5-year average baseline visibility conditions are associated with the date of December 31, 2004, and that natural visibility conditions are associated with the date of December 31, 2064, also clarifies that the period of time between the baseline period and natural visibility conditions, which is needed for determining the URP (deciviews/year) is 60 years.

Along with the clarification that the baseline period remains 2000-2004 for subsequent implementation periods, the EPA also proposed clarifications in 40 CFR 51.308(f)(1)(i) regarding how states treat Class I areas without available monitoring data or Class I areas with incomplete monitoring data, as follows: if Class I areas do not have monitoring data for the baseline period, data from representative sites should be used; if baseline monitoring data are incomplete, states should use the 5 complete years closest to the baseline period. We proposed to add this provision to remove any uncertainty about how an issue of data incompleteness should be addressed in a SIP.

Finally, we proposed language in 40 CFR 51.308(f)(3)(i) and an accompanying definition of "end of the applicable implementation period" in 40 CFR 51.301 to make clear that RPGs are to address the period extending to the end of the year of the due date of the next periodic comprehensive SIP revision.

2. Comments and Responses

Some commenters were supportive of EPA's proposal to have the URP line start at 2000-2004 for every implementation period, although some asked for the option of recalculating the URP for the start of each implementation period based on how much further progress is needed to reach natural conditions given the progress already achieved. Other commenters did not agree with EPA's proposal and instead supported a revision to the regulations that would require states to reset the URP at current visibility conditions during each periodic review, provided those visibility conditions are better than during the baseline. Taking into account past improvements in visibility that were in excess of the URP in this way would result in a lower-lying URP line for successive planning periods. This could change the comparison of the RPG to the URP line, and trigger the requirement of 40 CFR 51.308(f)(3)(ii) to show that there are no additional measures that would be reasonable to include in the long-term strategy, when it would not be triggered if the start of the URP line had been kept at the 2000-2004 period.

As explained in the 1999 RHR, the consideration of the improvement in visibility represented by the URP and the measures necessary to attain that level of improvement is an analytical requirement. In the 1999 RHR, EPA adopted this required analysis in lieu of establishing presumptive reasonable progress targets, in part to provide equity between the goals set for the Class I areas in the more impaired eastern portion of the country as compared to the areas in the western portion. The URP analysis also helps to provide transparency to the overall regional haze SIP planning process, in part by requiring states to compare their RPGs to the rate of progress represented by the URP at each Class I areas. Neither of these goals would be served by allowing states to adopt differing approaches to the calculation of the URP.

We have considered the comments suggesting that the URP be redrawn during each successive planning period. Although such an approach is apparently intended by commenters to maintain pressure on the states to adopt more comprehensive and effective reasonable progress strategies, it is not clear that this approach would in fact achieve that outcome because it may create disincentives for states to take aggressive action during the first few planning periods.

This is because resetting the URP would make it more likely that a state that has taken early and aggressive action to improve visibility would become subject to the enhanced analytical requirement of 40 CFR 51.308(f)(3)(ii), thus generating a possible disincentive for continued progress.

Because we have concluded that our proposed approach of starting the URP for every implementation period at 2000-2004 will result in the most equitable and transparent process and provide the strongest incentive for continued progress toward achieving natural visibility conditions, we are finalizing that approach with no changes to 40 CFR 51.308(f)(1)(i) or (vi).

3. Final Rule.

The EPA is finalizing all of the previously described rule text without any changes from the proposal.

The long-term strategy and the RPGs must provide for an improvement in visibility for the most impaired days and ensure no degradation for the clearest days.

1. Summary of Proposal

Section 169A of the CAA requires a SIP to not only reduce existing visibility impairment but also to prevent future impairment. As part of meeting the goal of preventing future visibility impairment, 40 CFR 51.308(d)(1) of the 1999 RHR requires a state to establish RPGs that ensure no degradation in visibility for the least impaired days over the period of the implementation plan. This text is ambiguous, however, as to whether "the period of the implementation plan" refers to the entire period since the baseline period of 2000-2004 or to the specific implementation period addressed by the periodic SIP revision. The proposal noted that a table in the preamble to the 1999 RHR summarizing certain requirements indicated that the 2000-2004 period would be used for "tracking visibility improvement."[98] To provide further clarity on this issue, we proposed new rule text in revised 40 CFR 51.308(f)(3)(i) that would make clear that the requirement is for a state to establish an RPG for the 20 percent clearest days in each periodic review that ensures that there is no deterioration in visibility on the 20 percent clearest days as compared to the baseline period of 2000-2004. We note that while 40 CFR 308(d)(1) of the 1999 RHR expresses the requirement of no degradation in visibility in terms of the RPG for the 20 percent clearest days, this requirement comes into play as a factor in what emission sources are subject to additional control measures in the long-term strategy, because this RPG is the projected result of implementing the long-term strategy. In other words, a state must adopt a long-term strategy that includes the necessary measures to ensure that the expected visibility on the 20 percent clearest days at the end of the planning period, as represented by the RPG for these days, will not deteriorate as compared to the visibility condition for these days in 2000-2004.The rule text we proposed for 40 CFR 308(f)(3)(i) made this connection explicit by saying that the long-term strategy and the RPG must provide for no degradation.

2. Comments and Responses

The EPA received comments both in support of, and raising concerns with, the proposed changes. The commenters opposed to our proposal preferred that when a state documents that the RPG for the 20 percent clearest days (i.e., the projected visibility condition on the clearest days as of the end of the given implementation period) shows no degradation, the benchmark for that comparison should be the lowest measured impairment of either the baseline period or current conditions reported in any progress report or comprehensive periodic revision for the clearest

[98] 64 FR 35730.

days. The approach recommended by the commenter would mean that the benchmark for the no degradation comparison would ratchet down over time.

One commenter pointed out that as proposed, 40 CFR 308(f)(3)(i) addressed not just the requirement for no degradation for the clearest days but also the requirement that there be an improvement for the most impaired days. This commenter noted that the relevant sentence of 40 CFR 308(f)(3)(i) could be interpreted to mean that the baseline period of 2000-2004 is the benchmark for determining if the long-term strategy and RPG for the most impaired days provides for an improvement.[99] The commenter said that the final rule should provide that the benchmark for the improvement requirement should be the lowest measured impairment of either the baseline period or current conditions reported in any progress report or comprehensive periodic revision for the most impaired days. The approach recommended by the commenter would mean that the benchmark for the improvement comparison would ratchet down over time.

We are finalizing our proposal to clarify that the benchmark for the requirement for no degradation on the 20 percent clearest days is the 2000-2004 baseline visibility condition. Further, we are clarifying that the baseline visibility condition for the 20 percent most impaired days is also the benchmark for the requirement that the long-term strategy and RPGs provide for an improvement for the most impaired days. We are taking this approach in the final rule for several reasons.

---

[99] The relevant sentence in the rule reads, "The long-term strategy and reasonable progress goals must provide for an improvement in visibility for the most impaired days and ensure no degradation in visibility for the clearest days since the baseline period." The concluding phrase "since the baseline period" can be taken to apply to only the clearest days, or to both the most impaired days and the clearest days.

Visibility on the clearest days has been improving since the 2000-2004 period in most Class I areas, generally tracking the improvements seen on the 20 percent haziest and 20 percent most impaired days.[100] We expect that it will continue to be the case that emission reduction measures that provide for reasonable progress on the 20 percent most impaired days will also have benefits on the clearest days. Thus, we expect that there will be a continuing improvement on the clearest days regardless of the benchmark selected, even if the rule did not contain any requirement for no degradation on the clearest days. Even so, we believe that the no degradation requirement with the 2000-2004 visibility condition as the benchmark is an appropriate backstop in the rule that will continue to require states to consider additional measures in the event that measures adopted to improve visibility on the most impaired days are insufficient to protect visibility on the clearest days.

We are not adopting the approach of ratcheting down the benchmark for the no degradation requirement. If we were to do this, it might lead to unreasonable outcomes in some cases. Available air quality modeling approaches for forecasting visibility conditions are at present more uncertain when predicting low concentrations of visibility-impairing pollution than when predicting higher concentrations, making comparisons of two "clean" scenarios more uncertain. Such comparisons could become required for many areas and have critical implications for SIP approvals. Errors in such comparisons due to modeling system errors might lead to inappropriate SIP disapprovals if the benchmark for the no degradation requirement continually ratcheted down as progress is made. Another consideration is that even with a 5-year

[100] The RTC contains graphics illustrating these improvement trends. The only situations in which there has been degradation since 2000-2004 are at a few Class I areas in the Virgin Islands and Alaska where sea salt particles significantly contribute to light extinction on the clearest days and concentrations of such particles on those days have increased over this period.

averaging approach, transient natural phenomena might cause a temporary improvement in visibility on the clearest days entirely unrelated to the content and implementation of states' long term strategies, which would permanently reduce the benchmark if the ratcheting approach were followed. It might then be very difficult or unreasonable for a state in subsequent periods to show no degradation relative to this lower benchmark given that on the clearest days influences from anthropogenic sources will be relatively small. Finally, we believe that consistency between the benchmark for the no degradation test and the starting point for the URP, across Class I areas in a given implementation period and across implementation periods, will aid public understanding and participation in SIP development. For these reasons, we are finalizing our proposal on this aspect of the RHR.

In addition, we are finalizing wording in 40 CFR 308(f)(3)(i) that makes it clear that the baseline condition in 2000-2004 is also the benchmark for determining whether the long-term strategy and RPGs provide for an improvement in visibility for the most impaired days, but repeating the reference to this baseline so that it links unambiguously to that requirement as well as to the no degradation requirement. We recognize that since 2000-2004 there have been widespread improvements in visibility on the most impaired days and that this already accomplished improvement has created a "cushion" for a comparison to check that the RPG for the end of a future implementation period shows improvement. However, we disagree with the commenter's suggestion that the benchmark for the improvement requirement should ratchet down over time, for similar but not entirely identical reasons that we disagree regarding the no degradation requirement. The advantage of consistency to public understanding applies to the improvement requirement as well as to the no degradation requirement. While the problem of modeling uncertainty applies less to the most impaired days at this stage of the regional haze program, in later periods the most impaired days will be clearer than they are now and the difficulty of distinguishing differences may apply more strongly. Also, we are mindful of the potential for reducing incentives for states to take action during the first few planning periods. With the 2000-2004 period as the benchmark for the no degradation requirement, a state has an incentive to take early action to improve the clearest days because this will create a safety margin in case later developments outside the state's control cause an increase in impairment on these days. Ratcheting down the baseline for the no degradation requirement would remove this incentive for continued progress because it would never be possible for a state to create a safety margin.

However, the use of the baseline period as the benchmark for the no degradation and improvement requirements does not mean that states are free to simply allow visibility levels to return to what they were in the baseline period, or to allow for degradation in visibility as compared to current conditions. If a state were to set an RPG that reflects a forecast of degradation during a particular period, the adequacy of the SIP would need to be carefully assessed. In this situation, additional measures may be necessary to ensure reasonable progress, depending on the underlying explanation for the forecasted degradation. It may be that a state would be able to show that any forecasted degradation is attributable to causes other than deficiencies in its long-term strategy, but such a demonstration would need to be carefully assessed. We note that for at least the next planning period or two, the requirement to consider the four statutory factors for a reasonably selected set of sources should result in the adoption of additional control measures that provide an improvement, especially for a state with sources that contribute to impairment at a Class I area with an RPG above the URP line.

3. Final Rule.

Upon careful consideration of public comments received on this issue, the EPA is finalizing the proposed rule with a clarifying edit to the proposed language to make it clear that the baseline visibility condition is also the benchmark for determining whether the long-term strategy and RPGs provide for an improvement in visibility on the most impaired days.

The sentences of the final version of 40 CFR 51.308(f)(1)(i), regarding the calculation of the baseline visibility conditions, have been slightly reordered and reworded from the proposed version for clarity. In addition, the final sentence of this paragraph, regarding Class I areas that did not have IMPROVE monitoring stations installed in time to provide complete monitoring data for 2000-2004, has been re-worded to clarify that "closest" means closest in time to 2000-2004 and does not refer to another Class I area that is nearest in distance. In the final version of 40 CFR 51.308(f)(1)(ii), an occurrence of "or" has been corrected to "and" to indicate that natural visibility conditions for both the most impaired days and the clearest days must be based on available monitoring information. Minor edits for clarity have also been included in the final versions of 40 CFR 51.308(f)(1)(iii) and (iv).

Analytical Obligation When the Reasonable Progress Goal for the 20 Percent Most Impaired Days Is Not On or Below the URP Line.

1. Summary of Proposal

The EPA proposed 40 CFR 51.308(f)(3)(ii) in order to clarify the relationship between the RPG for the 20 percent most impaired days and the URP line. This relationship determines the content of the demonstration a state must submit to show that its long-term strategy provides for reasonable progress. This clarification was based upon the 1999 RHR's text of 40 CFR 51.308(d)(1)(ii). That provision addresses required actions of a state containing a Class I area that has adopted an RPG for the area that provides for a slower rate of visibility improvement than that needed to attain natural conditions by 2064 (i.e., an RPG for the 20 percent most impaired days that is above the URP line). The proposed text of 40 CFR 51.308(f)(3)(ii)(A) stated that if the RPG for a Class I area is above the URP line, the state containing the Class I area must demonstrate, based on the four reasonable progress factors, that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that may be reasonably anticipated to contribute to visibility impairment that would be reasonable to include in the long-term strategy, and that such a demonstration is required to be "robust." Specifically, this demonstration must include documentation of the criteria used to determine which sources or groups of sources were evaluated and of how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.

In addition, in comparison with the 1999 RHR's 40 CFR 51.308(d)(2)(iv) and 40 CFR 51.308(d)(3)(i) and (ii), the proposed 40 CFR 51.308(f)(2)(iii) more clearly spelled out the respective consultation responsibilities of states containing Class I areas as well as states with sources that may reasonably be anticipated to cause or contribute to visibility impairment in those areas. To further clarify the obligations of what we are referring to as contributing states, we proposed 40 CFR 51.308(f)(3)(ii)(B) to specify that in a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders. This proposed change clarifies that the

RPG for the most impaired days in the SIP of the state containing the Class I area does not "set the bar" for the contributing state's long-term strategy.

2. Comments and Responses

The EPA received comments both in support of, and opposed to, the proposed changes. Comments opposing these provisions stated that this additional requirement goes beyond the CAA's requirement to consider the four statutory factors. The EPA disagrees with this assertion. Congress declared a national goal of preventing any future and remedying any existing visibility impairment in Class I areas resulting from manmade air pollution and delegated to EPA the authority to promulgate regulations assuring reasonable progress toward meeting that goal. CAA section 169A(a)(1), (a)(4). The analytical obligations contained in 40 CFR 51.308(f)(3)(ii) are a mechanism to ensure that states are, in fact, making reasonable progress by requiring states in certain circumstances to demonstrate the reasonableness of their four-factor analyses. In addition, some commenters suggested that the term "robust demonstration" is overly vague and expressed concern that, essentially, the EPA could take advantage of this vagueness in order to form its own criteria for disapproval of a SIP. Most commenters did not supply any specific suggestions, simply stating either that the term should be clarified or that this provision should not be finalized, although one commenter suggested states be allowed to refer to information already submitted or contained in an applicable docket for purposes of such a demonstration. We disagree that the requirement of a "robust demonstration" is vague. The provision requires the demonstration to be based on the analysis in 40 CFR 51.308(f)(2)(i), and further clarifies that the demonstration must document the criteria used to determine which sources or groups of sources were evaluated and how the four reasonable progress factors were considered. The purpose of this demonstration is to show that a state conducted its analysis in a reasonable manner and that there are no additional measures that would be reasonable to implement in a particular planning period. A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination. Additionally, the EPA recently issued a draft guidance document that addresses, among other things, the reasonable progress analysis, which we expect to finalize in the near future. This guidance can provide further direction regarding the types of information and analyses a state may provide in its demonstration under 40 CFR 51.308(f)(3)(ii). The EPA is therefore finalizing this provision as proposed. In addition, one commenter stated that the "robust demonstration" language of the proposed 40 CFR 51.308(f)(3)(ii)(A) was missing from the proposed 40 CFR 51.308(f)(3)(ii)(B). The EPA agrees the necessary text was missing from proposal, as states with Class I areas should be subject to the same type of demonstration as those contributing states without Class I areas. Therefore, the final rule includes in the requirements for a contributing state in 40 CFR 51.308(f)(3)(ii)(B) the same requirement for a robust demonstration that appeared only in 40 CFR 51.308(f)(3)(ii)(A) at proposal.

Some commenters stated a desire for corresponding rule text dealing with situations where RPGs are equal to ("on") or better than ("below") the URP or glidepath. Several commenters stated that the URP or glidepath should be a "safe harbor," opining that states should be permitted to analyze whether projected visibility conditions for the end of the implementation period will be on or below the glidepath based on on-the-books or on-the-way control measures, and that in such cases a four-factor analysis should not be required. Other commenters suggested a somewhat narrower entrance to a "safe harbor," by suggesting that if current visibility conditions are already below the end-of-planning-period point on the URP line, a four-factor analysis should not be required. We do not agree with either of these recommendations. The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress states must consider the four statutory factors.[101] Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period. Even if a state is currently on or below the URP, there may be sources contributing to visibility impairment for which it would be reasonable to apply additional control measures in light of the four factors. Although it may conversely be the case that no such sources or control measures exist in a particular state with respect to a particular Class I area and implementation period, this should be determined based on a four-factor analysis for a reasonable set of in-state sources that are contributing the most to the visibility impairment that is still occurring at the Class I area.[102] It would bypass the four statutory factors and undermine the fundamental structure and purpose of the reasonable progress analysis to treat the URP as a safe harbor, or as a rigid requirement.

3. *Final Rule*

The EPA is finalizing all of the previously described rule text without any changes from the proposal, with the exception of including in 40 CFR 51.308(f)(3)(ii)(B) the same requirement for a robust demonstration that appeared only in 40 CFR 51.308(f)(3)(ii)(A) at proposal.

---

[101] CAA section 169A(b)(2)(B), (g)(1).

[102] The point that having a RPG that is on or below the URP line is not a safe harbor has been articulated in past actions such as the disapproval of the reasonable progress element of Arkansas' SIP (*see* fn *32*). Our approval of the reasonable progress element of South Dakota's SIP is an example in which we approved the state's RPGs even though the RPG for the most impaired days for two Class I areas were above the respective URP lines, based on the state having adequately considered the four statutory factors for important contributing sources. 76 FR 76646 (December 8, 2011) (proposed action) and 77 FR 24845 (April 26, 2012) (final action).

Emission inventories.

1. Summary of Proposal

The EPA proposed language in 40 CFR 51.308(f)(2)(iv) regarding the "baseline emissions inventory" to be used by a state in developing the technical basis for the state's long-term strategy. This was done in order to reconcile this section with changes that have occurred to 40 CFR part 51, subpart A, Air Emissions Reporting Requirements, since the RHR was originally promulgated in 1999. The proposed changes were also intended to provide flexibility in the base inventory year the state chooses to use, as the EPA has always intended if there is good reason to use another inventory year.

2. Comments and Responses

Commenters were split on whether to support the flexibility afforded by the proposed rule text for selecting a year other than the most recent NEI year as the year of the inventory to be used as the basis for developing the long-term strategy. Some commenters supported the proposal, while others preferred that EPA require or definitively endorse that the 2011 NEI can be used as the base year for modeling for the next periodic comprehensive SIP revisions. The latter view generally resulted from concerns that while additional NEI versions, such as the 2014 and 2017 NEI versions, should be available by the time periodic comprehensive SIP revisions are due in 2021, there would not be adequate time after release of these inventories to complete all the modeling and analysis work required.

Consideration of these comments uncovered significant ambiguity in the text of 40 CFR 51.308(d)(3)(iii) of the 1999 RHR and ambiguity in the proposed new 40 CFR 51.308(f)(2)(iv) that would reflect 40 CFR 51.308(d)(3)(iii). Specifically, the term "the baseline inventory on which [the state's] strategies are based" in the 1999 RHR can be taken to refer to the inventory that is used to assess the contribution that sources make to visibility impairment (and the visibility benefits of additional control measures, when such benefits are considered) for individual sources or groups of sources. That information is critical to the development of the long-term strategy and, in that sense, is the information on which a state's strategies are to be based. However, we believe that some commenters have taken the term to refer to the inventory that is used as the expected starting point for the photochemical modeling that they (and we) expect will be used to project the RPG that quantifies the projected effect of all the measures in the long-term strategy and other influences on visibility at the end of the implementation period. The two bodies of information are not necessarily the same, and they do not necessarily even need to be for the same year in order to develop a SIP that provides for reasonable progress. In fact, the modeled RPGs that are eventually included in a SIP revision do not directly affect the development of the long-term strategy, but rather they reflect that strategy. We are revising the proposed regulatory text to make this clear. The final regulations use the "emissions information on which the State's strategies are based" to refer to the inventory that is used to assess the contribution that sources make to visibility impairment and not to the base year inventory used to model the RPGs.

The requirement in the final version of 40 CFR 51.308(f)(2)(iv) is that the emissions information on which the state is relying to determine the emission reduction measures that are necessary to make reasonable progress must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator under the Air Emissions Reporting Requirements. To allow time for this information to be used in SIP development, the rule provides for a 12-month "grace period" such that a submission to the NEI in the period 12 months prior to the due date of the SIP does not trigger this requirement. We agree with the comments to the effect that there is no reason why a state should not make at least some information for the year of its most recent submission to the NEI part of the basis for its determination of the emission reduction measures that are necessary to make reasonable progress. The state is not required to use the same information as was submitted to the NEI, and it should not if it has developed or received better information for that year since its NEI submission. A state may also consider information for a more recent year if it is available and is of sufficient quality. Therefore, we do not believe it is necessary or appropriate for the RHR to provide for an exception to the requirement as it is stated in this section of the rule text and interpreted here. A state that plans to use information other than what is in the most recent NEI version released by the EPA to develop its long-term strategy should consult with its EPA regional office to obtain the EPA's preliminary perspective on whether there is a reasonable basis for its planned approach. This should also be a topic of the ongoing consultation with affected FLMs.

The final version of 40 CFR 51.308(f)(2)(iv) does not address the question of the year to be used as the base year for emissions modeling of the RPGs. The EPA generally recommends that this be the year of the most recent NEI version that has been developed and validated enough to be appropriate for air quality modeling to support policy development. The final rule provides the EPA flexibility to approve a SIP based on another year if there are good reasons. States that believe that another year is more suitable should consult with the EPA Regional office about their reasons.

3. Final Rule

For the reasons described previously, and also here, the final language for 40 CFR 51.308(f)(2)(iv) differs somewhat from the wording we proposed with respect to the terminology used to refer to emissions inventories. The final version of this subsection of the rule refers to the "emissions information on which the state's strategies are based," rather than to a "baseline" emissions inventory. The final version also does not include a provision for EPA approval for selecting a year other than the year of the most recent submission under the Air Emissions Reporting Requirements as the year of the inventory to be used as the basis for developing the long-term strategy. However, the final rule provides a 12-month grace period for the use of the year of the most recent submission under the Air Emissions Reporting Requirements. The rule does not address the selection of a year as the base year for emissions modeling of the RPGs for the end of the implementation period.

EPA action on RPGs.

1. Summary of Proposal

The proposed language of 40 CFR 51.308(f)(3)(iv) was intended to make clear that in approving a state's RPGs, the EPA will consider the controls and technical demonstration provided by a contributing state with respect to its long-term strategy, in addition to those developed by the state containing the Class I area with respect to its long-term strategy. This clarification was proposed in light of the 1999 RHR's 40 CFR 51.308(d)(1)(iii), which only explicitly mentions the demonstration provided by the state containing the Class I area.

2. Comments and Responses

No comments were received that specifically addressed this proposed rule text.

3. Final Rule

The EPA is finalizing this rule text as proposed.

Progress report elements of periodic comprehensive SIP revisions.

1. Summary of Proposal

The proposed language in 40 CFR 51.308(f)(5) complemented proposed changes regarding progress reports and the proposal to eliminate separate progress reports being due simultaneously with periodic comprehensive SIP revisions by requiring periodic comprehensive SIP revisions to include certain information that would have been addressed in the progress reports. While the proposed language would expand the scope of periodic comprehensive SIP revisions, the same information would still be covered and states would no longer need to prepare and submit two separate documents (potentially containing overlapping content) at the same time.

2. Comments and Responses

Few comments were received that specifically addressed this proposed rule text. Those that did address these provisions supported the proposed changes, with one comment additionally suggesting use of the terminology "the most recent progress report" instead of "the past progress report," which EPA is incorporating into the final text (this is discussed later). In addition, one commenter noted that states should also be required to address the requirements of proposed 40 CFR 51.308(g)(8) in periodic comprehensive SIP revisions. Proposed 40 CFR 51.308(g)(6), renumbered in the final rule as 40 CFR 51.308(g)(8), requires progress reports to include a summary of the most recent assessment of smoke management programs operating within the state if such assessments are an element of the program. (As background, this is not a requirement of the 1999 RHR for either progress reports or periodic SIP revisions.) We agree that the provisions of 40 CFR 51.308(f)(5) do not contain a requirement similar to the requirement in proposed 40 CFR 51.308(g)(6) or final 40 CFR 51.308(g)(8). However, for any state where smoke from prescribed fires is a significant contributor to visibility impairment, the analysis that it will perform under 40 CFR 51.308(f)(3)(iv)(D) as finalized (the requirement for a state to consider basic smoke management practices and smoke management programs) will serve the same purpose as would requiring periodic SIP revisions to summarize the conclusions of the most recent assessment of an existing smoke management program.

3. Final Rule

The EPA is finalizing this rule text as proposed with only minor wording changes for clarity including a small change in wording in response to a public comment indicating confusion with the terminology "past progress report." The EPA agrees that this should instead refer to the "most recent progress report" and is finalizing revised text accordingly.

E. Changes to Definitions and Terminology Related to How Days Are Selected for Tracking Progress

1. Summary of Proposal

The 1999 RHR's 40 CFR 51.308(d) required states to determine the visibility conditions (in deciviews) for the average of the 20 percent least impaired and 20 percent most impaired visibility days over a specified time period at each of their Class I areas. As discussed in detail in the preamble of the proposed rule, the definition of visibility impairment included in 40 CFR 51.301 of the 1999 RHR suggests that only visibility impacts from anthropogenic sources should be included when considering the degree of visibility impairment. However, the approach followed for the first implementation period involved selecting the least and most impaired days as the monitored days with the lowest and highest actual deciview levels regardless of the source of the particulate matter causing the visibility impairment. While the EPA approved SIPs using this approach for the first implementation period, experience now indicates that for the most impaired days an approach focusing on anthropogenic impairment is more appropriate because it will more effectively track whether states are making progress in controlling anthropogenic sources. Our proposed approach is also more consistent with the definition of visibility impairment in 40 CFR 51.301. Because the 1999 RHR rule text already refers to the 20 percent most impaired days, we did not propose to change that wording. In the preamble to the proposal, we made clear that going forward, we would interpret "most impaired days" to mean those with the greatest anthropogenic visibility impairment, as opposed to the 20 percent haziest days. We did not propose to change the approach of using the 20 percent of days with the best visibility to represent good visibility conditions for RPG and tracking purposes, but we did propose a rule text change to refer to them as the 20 percent clearest days rather than the 20 percent least impaired days.

The proposal included changes to a number of the definitions in 40 CFR 51.301 as well as added definitions for some previously undefined terms, including *clearest days*, *the deciview index*, *natural visibility conditions* and *visibility*.

The EPA solicited comment on requiring all states to use the new meaning of "most impaired days" as referring to the days with the most anthropogenic impairment, as well as on a second proposed approach. In the second proposed rule alternative, states would be allowed to choose between selecting the 20 percent of days with the highest overall haze (i.e., the approach used in the first implementation period) and selecting the 20 percent of days with the most impairment from anthropogenic sources (the proposed new meaning). The EPA also solicited comment on any additional approaches.

2. Comments and Responses

We received some comments favoring the first proposed rule alternative that expressed support for a single, consistent approach to selecting the 20 percent most impaired days for all states. However, the majority of comments from states favored the second proposed rule alternative due to the flexibility it offered. Some comments on the second proposed rule alternative expressed concerns about, and requested guidance for, consultation between states in situations where two states use different approaches. Some comments favoring the second proposed rule alternative said that they anticipated that using the 20 percent most anthropogenically impaired days would mean an additional workload that would consume state resources during the planning process, and cited this as the reason they did not support the first proposed rule alternative. One commenter suggested that the final rule could allow states submitting their SIPs for the second implementation period by the 1999 RHR's deadline of July 31, 2018, to choose between using the 20 percent most anthropogenically impaired days or the 20 percent haziest days, with states submitting later required to use the latter approach.

After considering these comments and other considerations as described here, we are finalizing the first proposed alternative for the final rule (i.e., that "most impaired days" means those with the most anthropogenic impairment). The EPA often provides states flexibility when it may help achieve the objectives of SIP development and does not negatively implicate a program's objectives. In this particular situation, however, the flexibility of the second proposed rule approach would not significantly assist in developing efficient and effective SIPs and would likely result in confusion among stakeholders. For example, if two states with Class I areas in close proximity choose different approaches to the selection of days, the public might misunderstand how past and projected progress in improving visibility compares between the two areas. Also, allowing the state with a Class I area to unilaterally choose the selection approach for that area would raise the prospect that a contributing state might disagree with that choice, because the choice could make a difference in whether both states are subject to the enhanced analysis requirement of 40 CFR 51.308(f)(3)(ii), therefore complicating consultation among states. It would be possible for a state to choose a given approach simply because it would result in the best comparison of RPGs to the glidepath or URP for the implementation period being addressed by a SIP revision, and a state could conceivably switch back and forth between the two approaches from one period to another to get the best comparison for each period, causing additional confusion. In addition, we believe the approach of using anthropogenic impairment to select the 20 percent worst days is more consistent with the intent of the original RHR, namely to reduce the aggregate effect that anthropogenic sources have on the visual experience of visitors to Class I areas.

The EPA disagrees that concerns regarding additional workload and lack of resources preclude adopting the first proposed alternative. The EPA and IMPROVE program will work together to provide datasets that identify the most anthropogenically impaired days in each year of IMPROVE data and that contain the statistical summaries of these days need as part of a SIP revision or progress report. These datasets will be based on a specific method the EPA intends to recommend in a future guidance document. We expect that these datasets will avoid any increase in the workload and resources required of states relative to continued use of the haziest days. We will also work with any state or states interested in a different specific method for identifying the most impaired days than the one we will recommend, to avoid an increase in workload that would interfere with other aspects of SIP development.

The final rule revisions requiring states to use the 20 percent of days with the greatest anthropogenic impairment do not have any direct implications for how states develop their long-term strategies. While these revisions may affect whether a state has to demonstrate that there are no additional measures that would be reasonable to include in the long-term strategy under the requirement of 40 CFR 51.308(f)(3)(ii), these revisions do not prescribe how a state may make this demonstration. Thus, we believe that this requirement will not impair states' flexibility to appropriately analyze and address the sources of visibility impairment at Class I areas in and near their states.

We are not making any changes in response to the comment suggesting that the final rule provide flexibility in the approach to the selection of the worst days only for areas that submit their SIP revisions by July 31, 2018. It is our understanding that only some eastern states may be submitting SIP revisions this early and that the states involved have not been experiencing erratic impacts from wildfires and dust storms. Therefore, we do not believe the special flexibility the commenter suggests is needed. As mentioned, any state may choose to include in its SIP a second summary of visibility data using the 20 percent haziest days approach, for public information purposes.

Regarding the proposed changes to definitions, commenters recommended adding language to the definitions of *most impaired days*, *regional haze*, and *visibility impairment* to further clarify that these terms refer to impairment due to anthropogenic sources. The EPA agrees that some of the suggestions provided by commenters further clarify that visibility impairment is due to anthropogenic sources and does not include emissions from natural sources.

Therefore, in response to these comments, we have finalized additional changes to the definitions of *most impaired days, regional haze*, and *visibility impairment* to also include the concept that impairment is anthropogenic.

We also received comments on the proposed change to the definition of *natural conditions* and the proposed definition of *natural visibility conditions*. The commenters asked the EPA to further revise these definitions to reflect the reality that natural conditions have changed over time and will continue to change in the future; to make clear the timeframe of natural visibility conditions we intend to be captured by the definition; that natural visibility conditions may reflect poor visibility conditions; and to more explicitly include the factors contributing to natural visibility conditions (e.g., fire and dust events, volcanic activity, etc.). As a result of these comments, we are finalizing additional changes to these two definitions and adding definitions for two additional terms used in the rule. We are also providing further explanation of the role of natural visibility conditions in the SIP development process as follows.

The EPA is finalizing the definition of *natural conditions* to include a list of example phenomena considered to be a part of natural conditions. The list provided is not intended to be exhaustive, but provides examples of some of the types of natural impacts that may affect Class I areas. We are also finalizing the definition of *natural conditions* to reflect the EPA's understanding that natural conditions not only will vary with time, but that they also may have long-term trends due to changes in the Earth's climate system. We have also clarified in this definition that natural phenomena both near to and far from a Class I area may impact visibility in the Class I area.

To reduce confusion between the natural visibility that would exist on a single day and the average of a set of natural visibility values for a set of days, we are finalizing separate definitions of *natural visibility* and *natural visibility condition*. *Natural visibility* will refer to visibility on a single day. The *natural visibility* definition includes language that recognizes natural visibility does vary daily and may contain long-term trends. *Natural visibility condition* will refer to the average of a set of values on an indicated set of days.

In practice, the natural visibility condition for the 20 percent most impaired days is used by a state when developing the most appropriate 2064 endpoint for the URP line. Then the RPG for the 20 percent most impaired days is to be compared with the point on the URP line corresponding to the end date of the implementation period, which will in effect be adjusted by a portion of the adjustment made to the 2064 endpoint. The EPA invited comment on draft guidance[103] to the states on how to determine the value of the 2064 natural visibility condition for the 20 percent most impaired days for each Class I area for purposes of calculating the URP, and we intend to provide final guidance on this topic separately from this action on revisions to the RHR.

The need for clarity about the distinction between visibility on one day and the average of the visibility values for a set of days also applies to baseline visibility conditions and to current visibility conditions. To achieve this clarity, the final rule text includes new definitions of the terms *baseline visibility condition* and *current visibility condition*. These definitions are consistent with the way these terms are used in 40 CFR 51.308, but having these explicit definitions will improve understanding by participants in the regional haze program.

3. Final Rule

---

[103] Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period. 81 FR 44608 (July 8, 2016).

The EPA is finalizing the requirement that all states select the 20 percent most impaired days, i.e., the days with the most impairment from anthropogenic sources, as the "worst" days for purposes of calculating baseline visibility conditions, current visibility conditions, natural visibility conditions and the URP in SIPs and, as applicable, in progress reports. Under the final rule revisions, states retain the option to also present visibility data using the days with the highest overall deciview index values (i.e., the 20 percent haziest days), for public information purposes. Including this information in the SIP may help communicate to the public the magnitude of impacts from natural sources including wildland wildfires and dust storms. The RPGs and URP line that are calculated using anthropogenic impairment to select the most impaired days constitute the glidepath representing the state's determination of reasonable progress and, if appropriate, may trigger the requirement for a state to show that there are no additional emission reductions measures that would be reasonable to include in the long-term strategy (*see* Section IV.D of this document). Since the 20 percent most anthropogenically impaired days will, going forward, be used to estimate natural visibility conditions, current visibility conditions and the URP, they must also be used in setting RPGs and in progress reports. Conforming edits that were proposed to the provisions related to each of these calculations are likewise being finalized. As described at proposal, the revised approach will apply starting with the second and subsequent periodic comprehensive SIP revisions and will apply to progress reports starting with those submitted after the second SIP revision. EPA will continue to use the previous approach of considering the 20 percent haziest days with respect to SIP revisions submitted to satisfy the requirements of the first implementation period or initial progress reports.

The EPA did not propose to require any particular method for determining the natural versus anthropogenic contributions to daily haze and thus the degree of visibility impairment for each monitored day. The EPA issued draft guidance[104] describing a recommended approach along with a process for routinely providing relevant datasets for use by states when they develop their SIPs and progress reports. No particular method is being prescribed by the final rule nor will the final version of the guidance contain any binding requirements; states can therefore develop, justify and use another method of discerning natural and anthropogenic contributions to visibility impairment in their SIPs. The EPA intends to include more information on this subject in the final guidance.

As described in the summary of comments on this topic, the EPA is finalizing the proposed changes to the definitions of *clearest days*, *deciview, deciview index, least impaired days*, and *visibility* along with additional changes we have determined are needed to further clarify the definitions of *most impaired days, visibility impairment, regional haze, natural conditions,* and *natural visibility condition.* The additional changes to these proposed definitions are intended to more clearly explain that impairment is from anthropogenic sources and that natural sources and their contributions to visibility vary over time. Additionally, the EPA is finalizing definitions for *natural visibility, baseline visibility condition,* and *current visibility condition* that we determined are needed to fully clarify the meanings of these terms.

We are not finalizing the proposed change to the definition of a Federal Class I area that would have stated that non-mandatory Federal Class I areas are identified in 40 CFR part 52. There currently are no non-mandatory Federal Class I areas and the reference to 40 CFR part 52

---

[104] 81 FR 44608 (July 8, 2016).

could have created confusion. The final definition of a mandatory Class I Federal area correctly indicates that the mandatory areas are identified in 40 CFR part 81 subpart D.

F. Impacts on Visibility from Anthropogenic Sources Outside the U.S.

1. Summary of Proposal

In the proposal, the EPA acknowledged that emissions (natural and anthropogenic) from other countries and marine vessel activity in waters outside the U.S. may impact Class I areas, especially those areas near borders and coastlines. Prior to our proposal, several states with such Class I areas requested that they be allowed to adjust their URP line, visibility tracking metrics and RPGs to account for international anthropogenic impacts when preparing SIPs and progress reports.[105] We therefore solicited comment on a proposed provision that would allow states with Class I areas significantly impacted by international anthropogenic emissions to adjust their URPs with approval from the Administrator.[106] The proposed adjustment would consist of adding to the value of the natural visibility condition for the 20 percent most impaired days in 2064 an estimate of the average impact from international anthropogenic sources on such days,

---

[105] The impacts from natural sources located outside the U.S. can be large in certain Class I areas, but because the RHR treats impacts from all natural sources equally, those impacts are inherently properly included in the 2000-2004 baseline condition used as the starting point for the URP line and the natural visibility condition used as the 2064 endpoint of the URP line. Thus, the logical interest of these states was in a special adjustment for the impacts of anthropogenic sources outside the U.S. We note for clarity that under the final rule, prescribed fires outside of the U.S. are considered anthropogenic sources and thus the discussion in this section is relevant to such prescribed fires. Prescribed fires in wildland are also addressed in Section IV.G of this document.

[106] The 1999 RHR provided that if a state found that international emissions sources were affecting visibility conditions in a Class I area or interfering with plan implementation, that state could submit a technical demonstration in support of its finding. If EPA agreed with the finding, it would "take appropriate action to address the international emissions through available mechanisms." 64 FR 35714, 35747 (July 1, 1999).

[107] for the sole purpose of calculating the URP.[108] We also solicited comment on another possible approach to accounting for international anthropogenic impacts, in which the influence of emissions from anthropogenic sources outside the U.S. would be removed from estimates of 2000-2004 baseline visibility conditions, current visibility conditions and the RPG for the end of an implementation period.

The proposal reflected the EPA's position that it may be appropriate to allow a state to adjust the RPG framework, including in its progress reports, to avoid any perception that a state should be aiming to compensate for impacts from international anthropogenic sources and to avoid requiring a state to undertake the additional analytical requirement under 40 CFR 51.308(f)(3)(ii) based solely on visibility impairment due to international anthropogenic sources. However, we proposed that an adjustment to compensate for such impacts would be available only when and if these impacts can be estimated with sufficient accuracy. In the proposal we stated that we do not expect that explicit consideration of impacts from anthropogenic sources outside the U.S. should or would actually affect the conclusions that states make about what emission controls for their own sources are necessary for reasonable progress. However, we explained that explicit quantification of international anthropogenic impacts, if accurate, could improve public understanding and effective participation in the development of regional haze SIPs. We also indicated that while we had not yet, at the time of the proposal, seen an approach that would allow states to adjust their visibility tracking metrics with sufficient accuracy, we

[107] The URP line is expressed in deciview units, so the value added to the natural visibility condition would also be in deciviews. However, that added deciview value would be based on the light extinction increments caused by the indicated sources.
[108] This proposed extra step in determining the URP was not intended to have the effect of defining international anthropogenic sources as natural, or to change any other aspect of SIP development.

expected that by the time some future periodic comprehensive SIP revisions are to be prepared, methods and data for estimating international anthropogenic impacts will be substantially more robust. Our proposal did not include any statement about whether EPA would provide estimates on international impacts or guidance on how states can estimate such impacts.

2. Comments and Responses

Some commenters opposed allowing any adjustment to the URP, while others supported some sort of adjustment based on the impacts of international anthropogenic sources. Several commenters stated that the EPA or other federal entities should provide an approach to estimating international anthropogenic impacts, or actual estimates of such impacts, that are presumptively approvable, or that the EPA should give deference to any estimate a state develops. Some commenters inferred that the EPA's statements in the proposal regarding the current state of the art for estimating international anthropogenic impacts meant that no state would be able to obtain EPA approval for an adjustment in the SIP due in 2021. Several commenters objected to their understanding that the proposed rule would require a state to obtain EPA approval for a particular adjustment approach before including such an approach in its SIP submission. Finally, at least one commenter requested that EPA also provide rule language allowing for adjustment of the 20 percent clearest days framework to reflect the impacts of international anthropogenic sources.

The EPA does not have a near-term plan to develop guidance on estimating international anthropogenic impacts or to provide such estimates specifically for the purpose of regional haze SIPs. However, the EPA is an active participant in research in this area and will continue to share its work with interested states and with others.[109] To clarify, the statements in the preamble regarding the state of the art method refer to our assessment of the estimates and models for estimating international impacts available in the scientific literature at the time of this rulemaking. We did not intend to preclude or prejudge consideration of estimates that states may include in SIPs for the second implementation period or subsequent periods based on newer and more refined methodologies and/or information. Although we do not believe such estimates and models are currently able to adequately represent the impacts of international anthropogenic sources on visibility, we acknowledge that this is an area of active research and development that may lead to adequate estimates in time for the development of SIPs for the second implementation period. Additionally, the final rule text includes a small change to clarify that the Administrator's approval for an adjustment will be part of the Administrator's review of the full SIP submission for an implementation period, and not a separate action in advance of SIP submission. In this way, the Administrator's decision to approve or not approve the adjustment will be made in the context of the complete SIP submission, with public notice and an opportunity to comment. As with any SIP element, states are encouraged to consult with EPA Regional offices during the development of any proposed adjustment approach.

---

[109] For example, the EPA held a 2-day workshop in February 2016 to advance the collective understanding of technical and policy issues associated with background ozone, which includes impacts from anthropogenic sources outside the U.S., as part of the agency's ongoing efforts to engage with states and stakeholders on implementation of the 2015 ozone NAAQS. While this workshop focused on ozone, the modeling issues and approaches for ozone are similar to those for visibility-impairing pollutants. More information on the EPA's activities and current understanding of this area can be found in the white paper available at *https://www.epa.gov/ozone-pollution/background-ozone-workshop-and-information* and other documents available in EPA number EPA-HQ-OAR-2016-0097 at *https://www.regulations.gov*.

Because the EPA is not providing estimates of international anthropogenic impacts or guidance for calculating those impacts at this time, we are not specifying that any such estimates or methodologies are presumptively approvable. We further disagree with comments that states have inherent discretion to adjust their URP and RPG frameworks to account for impacts of international anthropogenic sources and that the EPA lacks the authority to review such adjustments. As explained in Section IV.B of this notice, the CAA mandates that the EPA promulgate regulations requiring that states' SIP submittals contain, among other things, "measures as may be necessary to make reasonable progress toward meeting the national goal."[110] Furthermore, the EPA is required to ensure that states' submittals meet the basic legal requirements and objectives of the CAA, including any regulations the agency promulgates for the purpose of ensuring that states make reasonable progress towards achieving natural visibility. A proposed adjustment to a state's RPG framework to address the impacts of international anthropogenic sources has the potential to affect that state's assessment of what constitutes reasonable progress. Thus, the EPA not only has the authority to review a state's proposed adjustment, it has an obligation to do so.

Finally, we disagree with the comment that we should provide rule language for states to adjust their frameworks for assessing visibility on the 20 percent clearest days to account for any impacts of international anthropogenic sources. First, particular days on which international anthropogenic sources have particularly strong impacts due to unusual source events or transport conditions are unlikely to be among the 20 percent clearest days in their respective years. The commenter presented no basis for anticipating that increasing impacts from anthropogenic

---

[110] CAA section 169A(b)(2).

sources on the clearest days might cause a state to be unable to satisfy the no degradation requirement without employing unreasonable measures for domestic sources. Second, our analysis indicates that such an adjustment would not have been necessary in the first implementation period, in that nearly all Class I areas in fact have had no degradation during this period so far, and the few that have experienced degradation have not done so because of impacts attributable to international anthropogenic sources. Improvements in visibility on the 20 percent clearest days have been significant enough so that we expect that states impacted by increased emissions from international anthropogenic sources in the second implementation period will still be able to comply with the requirement that visibility on those days show no degradation compared to 2000-2004 baseline conditions. The RTC contains more information on this improvement trend. The EPA will continue to assess this relationship throughout the second and subsequent implementation periods. Third, on clear days when there is relatively little visibility-impairing air pollution, it is difficult with our current tools to discern the portion of that air pollution originating from international anthropogenic sources, as opposed to domestic anthropogenic or natural sources and as compared to the assessment of the impact of international anthropogenic sources on the most impaired days. It would thus be unlikely that a state could estimate international anthropogenic impacts on the 20 percent clearest days with the requisite degree of accuracy at this time or when developing a SIP for the second implementation period.

3. Final Rule

The EPA is finalizing the provision to allow an adjustment of the URP by adding an estimate for international anthropogenic impacts to 2064 natural visibility conditions. We are not finalizing the alternative approach to accounting for international anthropogenic impacts that would have involved removing the influence of emissions from anthropogenic sources outside the U.S. when developing the estimates of 2000-2004 baseline visibility conditions, current visibility conditions and the RPGs. We are finalizing only one approach to provide consistency and transparency, as the alternative approach would have been more complicated and involved presenting numerous counterfactual values of visibility levels that could be mistaken as actual measured values.

Because this adjustment is permitted only if the Administrator determines that a state has estimated the international impacts from anthropogenic sources outside the U.S. using scientifically valid data and methods, we are finalizing the rule text of 40 CFR 51.308(f)(1)(vi)(B) as proposed, with a small change to clarify singular versus plural,[111] as well as the aforementioned change to clarify that the Administrator's approval for an adjustment will

[111] Our proposed rule text used the phrase "the State must add the estimated impacts [of international anthropogenic sources (or certain prescribed fires)] to *natural visibility conditions* and compare the resulting value to *baseline visibility conditions*." For consistency with our final definitions, this part of the final rule text instead refers to the *natural visibility condition* and *the baseline visibility condition*. The use of the plural form for "natural visibility conditions" and "baseline visibility conditions" could give the impression that multiple values of impacts are to be added to multiple values of natural visibility conditions, when actually a single value reflecting impacts from international anthropogenic sources (or certain prescribed fires) is to be added to the single value of the "natural visibility condition" for the 20 percent most impaired days. The final rule text does not specify that the average of estimates of daily international impacts be used in this addition step, so that states can propose and the Administrator can approve another statistic to represent the distribution of daily values, for example the median value, if more appropriate.

be part of the Administrator's review of the full SIP submission for an implementation period, and not a separate action in advance of SIP submission.

In addition, we are finalizing the proposed rule text changes in 40 CFR 51.308(f)(1)(i) and 40 CFR 51.308(f)(1)(vi) to remove "needed to attain natural visibility conditions" from the reference to "uniform rate of progress," because when adjusted to reflect international impacts the "uniform rate of progress" would not be the rate of progress that would reach true natural visibility conditions.

Because the manner in which a state with a Class I area calculates the URP may affect other states with sources that contribute to visibility impairment at the Class I area,[112] we recommend that a state seeking approval for such an adjustment first consult with contributing states. Such an adjustment should also be a topic for the required consultation with the FLM for the Class I area at issue.

G. Impacts on Visibility from Wildland Fires

1. Summary of Proposal

Fires on wildlands within and outside the U.S. can significantly impact visibility in some Class I areas on some days but have little to no impact in other Class I areas. And even in those Class I areas significantly impacted by fires on wildlands on some days, there are a greater number of days where fires do not have such impacts. The EPA presented an extensive discussion of wildland fire concepts, including actions that the manager of a prescribed fire can take to reduce the amount of smoke generated by a prescribed fire and/or to reduce public

[112] Contributing states may be affected because under the final version of 40 CFR 51.308(f)(3)(iv)(B), a contributing state will have an additional analytical requirement if the RPG does not provide for the URP at an affected Class I area in another state.

exposure to the smoke that is generated (i.e., basic smoke management practices), in the proposed and recently finalized revisions to the Exceptional Events Rule.[113] That discussion is not repeated here.

The preamble for our proposed action discussed at length how the RHR relates to the management of wildland wildfires and wildland prescribed fires. The information presented there is applicable to states as guidance under these final RHR revisions, except as revised or supplemented as follows. There were many public comments on the subject of wildland fires, some of which are addressed in this section. We address the remaining comments in the RTC document for this action.

We proposed new definitions for wildland, wildfire and prescribed fire. These proposed definitions were consistent with the definitions we had recently proposed be added to the Exceptional Events Rule. We said in the proposal for the Exceptional Events Rule that wildland can include forestland, shrubland, grassland and wetlands, and that the proposed definition of wildland includes lands that are predominantly wildland, such as land in the wildland-urban interface. The proposed definition for wildfire included a provision that a wildfire that occurs predominantly on wildland is a natural event.

We also proposed language for new 40 CFR 51.308(f)(2)(vi)(E) based on the provisions of the 1999 RHR's 40 CFR 51.308(d)(3)(v)(E), with updates to reflect terminology used within the air quality and land management communities. Specifically, we proposed to use the term

---

[113] 80 FR 72840 (November 20, 2015); 81 FR 68216 (October 3, 2016). Both the preamble and final rule of the Exceptional Events Rule listed six basic smoke management practices with an important footnote which recognizes that those listed are not intended to be all-inclusive for the purpose of the Exceptional Events Rule. Section IV.G.2 of this document discusses the term "basic smoke management practices" in the context of the Regional Haze Rule.

"basic smoke management *practices*" to better align with current usage of "smoke management practices" in the fire management community to refer to steps that a burn manager can take to reduce emissions during a prescribed fire. We also proposed to use the term "wildland vegetation management purposes" in lieu of "forestry management purposes." This latter change was proposed in recognition of the fact that not all wildland for which fire and smoke are issues is forested. We also proposed to replace the phrase "including plans as currently exist within the State for these purposes" with "and smoke management programs for prescribed fire as currently exist within the State." The term "smoke management program" is used within the fire management community to refer to a multi-participant program that seeks to influence or regulate both whether and when prescribed fires are conducted and, typically, the smoke management practices employed during a prescribed fire. We stated in the preamble of the proposal that this required consideration of smoke management programs only applies if the existing smoke management program has six key features: (i) authorization to burn, (ii) minimizing air pollutant emissions, (iii) smoke management components of burn plans, (iv) public education and awareness, (v) surveillance and enforcement and (vi) program evaluation.

We proposed that for a state with a long-term strategy that includes a smoke management program for prescribed fires on wildland, each required progress report must include a summary of the most recent periodic assessment of the smoke management program including conclusions the managers of the smoke management program or other reviewing body reached in the assessment as to whether the program is meeting its goals regarding improving ecosystem health and reducing the damaging effects of catastrophic wildfires. (Comments on this proposal are summarized in Section IV.H of this document.)

We proposed that the Administrator may approve a state's proposal to adjust the URP to avoid subjecting a state to the additional analytical requirement of 40 CFR 51.308(f)(3)(ii) due to the impacts of wildland fire conducted with the objective to establish, restore and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species for purposes of ecosystem health (objectives that we refer to here as "wildland ecosystem health") and public safety during which appropriate basic smoke management practices were applied. This aspect of the proposal did not address and did not apply to fires of any type on lands other than wildland or to burning on wildland that is for purposes of commercial logging slash disposal rather than wildland ecosystem health and public safety. This aspect of the proposal was not restricted to prescribed fires within the U.S.

We proposed to revise the definition of "fire" to remove the phrase "prescribed natural fire." However, we stated that the definition of "fire" that would be revised appears in 40 CFR 51.301, when it actually appears in 40 CFR 51.309(b)(4) and applies only to 40 CFR 51.309. We inadvertently did not make any change to 40 CFR 51.309(b)(4) in our proposed rule text. We proposed this revision to remove "prescribed natural fire" from the "fire" definition because the concept of a "prescribed natural fire" is inconsistent with our proposal that all prescribed fires be considered anthropogenic sources. We recognize that some prescribed fires are intended to emulate and/or mitigate natural wildfires that would otherwise occur at some point in time. We also recognize that some wildfires are appropriately allowed to proceed for some time over an area without suppression in order to help achieve land management objectives. However, to use the term "natural" and "prescribed" in one definition would cause confusion.

While the direction of these proposals was towards providing states considerable flexibility regarding measures to limit emissions from wildland prescribed fire after having given reasonable consideration to their options, it was not and is not our intention to in any way discourage federal, state, local or tribal agencies or private land owners from taking situation-appropriate steps to minimize emissions from prescribed fires on wildland or prescribed fires on other types of land.

2. Comments and Responses

With regard to the definitions of prescribed fire and wildfire and the related question of whether each type of wildland fire should be considered as an anthropogenic versus non-anthropogenic event or source, some commenters said that all wildland prescribed fires, or at least all prescribed fires conducted under a smoke management program, should be treated as non-anthropogenic. Other commenters said that all or some wildfires should be treated as anthropogenic, noting that the occurrence of wildfires is not purely natural in that past human actions have affected fire risks and that current actions by humans initiate some wildfires. We disagree with these and similar comments. We recognize that prescribed fires in many cases are conducted because natural wildfires have been previously suppressed, or as a substitute for waiting for a wildfire to take place because conditions are such that a wildfire would pose high risks. We also recognize that human actions, in particular the suppression of wildfires in the past, have affected the propensity of some wildlands to experience wildfires from natural ignition sources such as lightning and that human actions such as arson or careless smoking, fireworks, target practice or backyard burning are the sources of the ignition of many wildland wildfires. Thus, there is some basis for the perspective that prescribed fires merit being treated somewhat like natural sources, as well as for the opposite view that wildfires merit being treated somewhat as anthropogenic sources. However, by declaring in section 169A(a) of the CAA a national goal of remedying visibility impairment in Class I areas "which impairment results from man-made air pollution," Congress established a bifurcation between anthropogenic and non-anthropogenic sources of air pollution. Given that prescribed fires involve conscious planning by humans, it would be unreasonable for the rule to categorically consider them to be natural events and natural sources of air pollution.[114] We consider wildfires having natural causes of ignition to be natural sources of air pollution. The provision that a wildfire that occurs predominantly on wildland is a natural event also encompasses wildfires initiated by human action because it is not always possible to determine the cause of ignition for some wildfires, and because once ignited the progress of these wildfires is largely determined by factors beyond human control at the time. Therefore, it is appropriate to treat both wildland wildfires with natural sources of ignition and the other types of wildfires encompassed by the definition in 40 CFR 51.301 as natural events and natural sources of air pollution.

These categorizations do not mean that prescribed fires necessarily should or can be regulated in a manner similar to sources that are more purely anthropogenic, such as industrial sources, or that no consideration should be given to how human actions affect wildfire occurrence. For the regional haze program, an implication of these categorizations is that states are not required to consider additional measures to reduce visibility impacts from wildfires when they develop their regional haze SIP submissions. However, we believe that it is in the public interest for states, and all managers of wildland, to consider such measures to limit wildfire

[114] As explained in footnote 95, the rationale for allowing an adjustment of the URP framework to address the impacts of wildland prescribed fires does not stem from the fact that we are treating these fires as natural sources of air pollution, as this is not the case. Rather, we are providing for an adjustment because we acknowledge that anthropogenic prescribed fire conducted for purposes of ecosystem health and public safety during which appropriate basic smoke management practices have been applied can be consistent with the goal of making reasonable progress towards natural visibility.

impacts on visibility on an ongoing basis. We encourage them to do so, to help improve visitor experiences in Class I areas, to protect public safety and health and to protect ecosystems from the impacts of catastrophic wildfires. We also believe that it is in the public interest for states, and all land managers using prescribed fire, to consider measures that can reduce the impact of prescribed fires on visibility in Class I areas and other air quality objectives. As they consider measures to reduce the impacts of prescribed fires on visibility, states may consider the benefits of wildland prescribed fire use (including benefits to ecosystem health and reduction in the risk of catastrophic wildfires) and the opportunity provided by the final rule for a state to make an adjustment to the URP to account for the impact of certain prescribed fires.

Regarding the proposal that would allow the Administrator to approve an adjustment to the URP for impacts from at least some wildland prescribed fires, some comments were in favor of this provision while others suggested minor changes to the proposed approach. Many comments did not support all the specifics of our proposal for adjustment of the URP. Many commenters also said that the EPA or the FLMs should provide guidance on how to estimate prescribed fire impacts for the purposes of this adjustment and/or provide the adjustment values themselves.

Of those commenters who did not support all the specifics of our proposal, one commenter said that states should be required to apply the four statutory factors to prescribed fire in order to be eligible to make any adjustment to the URP for prescribed fire impacts. Other commenters said that adjustment should be allowed only for prescribed fires conducted in accordance with any applicable smoke management program. However, other commenters said that an adjustment should be allowed to reflect the impacts of all types of prescribed fire and not merely those that met the conditions proposed by the EPA based on ecosystem or public health protection and use of basic smoke management practices.

We disagree with commenters that the adjustment of the URP should be based on the impact of all prescribed fires, or all wildland prescribed fires, rather than only wildland prescribed fire conducted for purposes of ecosystem health and public safety during which appropriate basic smoke management practices have been applied. The fires that meet these conditions are fires conducted for purposes and in accordance with practices that are consistent with the goal of making reasonable progress towards natural visibility. We note, however, that the availability of an adjustment to the URP for the impacts of these particular prescribed fires does not in any way restrict a state from considering additional measures or management programs to address their impacts on visibility. We recommend that as a state considers such measures, it should consult with managers of federal, state and private lands that would be subject to such measures; this may include federal agencies in addition to the federal land manager of the Class I areas affected by sources in the state, with whom consultation on the development of the SIP is a requirement of the final rule. Furthermore, it is appropriate that for prescribed fires conducted on lands other than wildlands, wildland fires conducted for other purposes and wildland fires conducted without application of basic smoke management practices, the URP should assume their impacts will diminish to zero by 2064, just as the URP effectively assumes with respect to other types of anthropogenic sources within the U.S.[115] This will focus public and state attention on whether there are any reasonable measures for reducing

[115] If there is no adjustment of the 2064 endpoint of the URP line for impacts from international anthropogenic sources, the URP effectively assumes that emissions from these sources will be zero in 2064. If there is an adjustment, the URP effectively assumes that these sources continue to have emissions in 2064.

impacts from these other types of prescribed fires. We also disagree with other commenters who recommended that the adjustment be more restrictive and apply only to prescribed fires conducted in compliance with a smoke management program, because this would make the adjustment unavailable to some states where it would be consistent with the goal of making reasonable progress and where an adjustment would be an appropriate efficiency and public communication approach.

We also disagree with commenters that states should be required to conduct a four-factor analysis for prescribed fire before being eligible to adjust their URPs for the impacts of such fires. As we explained earlier, we are limiting the availability of an adjustment to only those wildland prescribed fires conducted for the purposes of ecosystem health and public safety and in accordance with basic smoke management practices. These particular types of fires are generally consistent with the goal of making reasonable progress because they are most often conducted to improve ecosystem health and to reduce the risk of catastrophic wildfires, both of which can result in net beneficial impacts on visibility. [116] Therefore, as long as these fires are conducted in accordance with basic smoke management practices, an additional four-factor analysis in this specific case might serve no purpose. States may consider additional measures to address the impacts of these and other types of prescribed fires, on the basis of a formal four-factor analysis if they choose or after another form of consideration. [117]

One commenter suggested that an adjustment for the impacts of prescribed fires also be allowed as part of the demonstration that the long-term strategy and RPGs ensure no degradation on the clearest days. We disagree with this suggestion. First, the impacts from prescribed fires

[116] There is similarity and a difference in the rationales for an adjustment of the URP related to impacts from anthropogenic sources outside the U.S. and an adjustment related to impacts from wildland prescribed fire conducted for reasons of ecosystem health and public safety with appropriate basic smoke management practices applied. Because states cannot control and should not be expected to compensate for impacts from international anthropogenic sources, such international impacts should not be the sole reason that the RPG is above the URP line. In contrast, states generally have authority to regulate wildland prescribed fires within their borders. However, because it is generally reasonable for wildland prescribed fires of the type described to be conducted as determined to be needed through appropriate planning processes, with appropriate basic smoke management practices to reduce smoke impacts on the public, states should have the flexibility to determine that limiting the number of such wildland prescribed fires is not necessary for reasonable progress. SIP development can be more efficient and the public will better understand the progress being made to control other types of sources if the URP is adjusted to remove the influence of any projected increase in application of this type of wildland prescribed fire. Also, as with international anthropogenic impacts, this will avoid such fire impacts from being a critical factor in whether the RPG is above the URP line.

[117] Another way of considering whether measures in addition to BSMP are appropriate for prescribed fires conducted to improve ecosystem health and to reduce the risk of catastrophic wildfires, and/or considering what measures are appropriate for other types of prescribed fires, could be to assess and conclude that a particular sub category of prescribed fires does not meaningfully impact visibility at any Class I area. Such a conclusion could support a decision not to require additional measures for that subcategory in the LTS even though a formal four-factor analysis has not been completed. A state might also include in its LTS measures aimed at reducing impacts from a subcategory of prescribed fire because those measures are already in effect in the state due to another CAA requirement or due to state-only considerations. If so, a new formal four-factor analysis of those measures would not be useful.

will necessarily be small on the clearest days. The commenter presented no basis for anticipating that increasing impacts from prescribed fire on the clearest days might cause a state to be unable to satisfy the no degradation requirement without employing unreasonable measures for other source types. Second, our analysis indicates that such an adjustment would not have been necessary in the first implementation period, in that nearly all Class I areas in fact have had no degradation during this period so far, and the few that have experienced degradation have not done so because of impacts attributable to prescribed fire. Improvements in visibility on the 20 percent clearest days have been significant enough so that we expect that states impacted by increased emissions from prescribed fire in the second implementation period will still be able to comply with the requirement that visibility on those days show no degradation compared to 2000-2004 baseline conditions. The RTC contains more information on this improvement trend. The EPA will continue to assess this relationship throughout the second and subsequent implementation periods. Finally, on clear days when there is relatively little visibility-impairing air pollution, it is difficult with our current tools to discern the portion of that air pollution originating from prescribed fire, as opposed to the assessment of the impact of prescribed fire on the most impaired days. It would thus be unlikely that a state could estimate prescribed fire impacts on the 20 percent clearest days with the requisite degree of accuracy at this time or when developing a SIP for the second implementation period.

Regarding our proposal to use updated terminology in proposed 40 CFR 51.308(f)(2)(vi)(E), some commenters said that "basic smoke management practices" was not the appropriate update of the term "smoke management techniques" because the latter term is not explicitly restricted to "basic" techniques. We disagree with the commenter that the phrase "basic smoke management practices" could be interpreted as requiring a state to consider a narrower set of practices than the phrase "smoke management techniques." The EPA listed six basic smoke management practices in both the preamble and final rule of the Exceptional Events Rule with an important footnote which recognizes that those listed are not intended to be all-inclusive for the purposes of the Exceptional Events Rule. We similarly consider the term "basic smoke management practices" in the context of the Regional Haze Rule as allowing for additional basic smoke management practices to be developed to address Class 1 visibility impacts. In addition, this paragraph of the Regional Haze Rule specifies what a state at a minimum must consider, and a state may consider other measures as well. Accordingly, the final rule text in 308(f)(2)(iv)(D) contains the phrase "basic smoke management practices."

No commenters opposed the use of "and smoke management programs" in proposed 40 CFR 51.308(f)(2)(vi)(E) in place of "including plans" in 40 CFR 51.308(d)(3)(v)(E). However, there were other comments on proposed 40 CFR 51.308(f)(2)(vi)(E) that concern the proposed retention and meaning of the phrase "as currently exist within the State for these purposes. "One commenter supported the concept that only states with existing smoke management programs should be subject to this specific requirement to consider smoke management programs. Another commenter said that even with this restricted applicability, the requirement to consider smoke management programs was too prescriptive and states should be allowed to apply the same consideration to prescribed fires as generally apply for all sources. One group of commenters opposed the restriction to only states with existing smoke management programs, and further suggested that listing only smoke management practices and smoke management programs was insufficient and that the rule should also require all states to consider other measures to mitigate the impact of fire.

After consideration of these comments and a review of how the EPA and the states have applied 40 CFR 51.308(d)(3)(v)(E) during the first implementation period, we decided that finalization of the phase "as currently exist with the State for these purposes" cannot be said to clearly be only a preservation of the existing requirement of the 1999 RHR, particularly when combined with the replacement of "including plans" with "and smoke management programs." In the first implementation period the EPA never relied on a narrow interpretation of the applicability of this part of 40 CFR 51.308(d)(3)(v)(E) in reviewing a SIP. The final rule does not include the phrase "as currently exist with the State for these purposes" because we have decided that there is no rational basis for the restriction.[118]

The final version of 40 CFR 51.308(f)(2)(iv)(D) (renumbered) requires that states *consider* basic smoke management practices and smoke management programs when developing their long-term strategies. As discussed in the preamble to our proposed action,[119] these requirements do not require a state to adopt basic smoke management practices or programs into its regional haze SIP.[120] As states consider whether to adopt new measures that might affect the ability of land managers to use prescribed fire, they may newly consider both the effectiveness of their smoke management programs in protecting visibility and the benefits of wildland prescribed fire for ecosystem health and public safety. There are many ways that a state can give new consideration to such practices and programs. For example, a state can consider the need for

[118] Given the removal of the phrase "as currently exist within the state," the interpretation we articulated in the proposal that this phrase refers only to smoke management programs with the six listed features listed in the proposal is no longer relevant.
[119] *See* 81 FR 26958–59.
[120] Also, the EPA is not recommending that all states adopt any particular measures for wildland fire because situations vary too much from state to state and within states for any general recommendation to be appropriate.

including such measures in its SIP without shoehorning them into a formal four-factor analysis. A state can also consider them by determining based on analysis of IMPROVE data that fires in general, and thus prescribed fires in particular, are not a significant contributor to reduced visibility at the Class I areas in the state (or impacted by the state). Therefore, this requirement of the final rule will not impose a difficult analytical burden on states or require them to adopt unreasonable measures. However, a state cannot unreasonably determine that a requirement for burn managers to use certain basic smoke management practices *is not* necessary to make reasonable progress. If a state determines that a requirement for burn managers to use certain smoke management practices *is* necessary to make reasonable progress, the long-term strategy must include such measure(s) in enforceable form. The same applies to consideration of a smoke management program. One possible outcome may be that a state reasonably does not make such a formal determination, but nevertheless decides to revise its current program regarding prescribed fires without incorporating the program (or the program enhancements) into the SIP. Such an action could indicate that the state has satisfied the requirement to consider basic smoke management practices and smoke management programs.

States also have the flexibility to allow reasonable use of prescribed fire. As previously noted, one approach to reducing the occurrence of wildland wildfires, and the risk of wildfires having catastrophic impacts, is appropriate use of prescribed fire. The EPA and the federal land management agencies will continue to work with the states as they consider how use of prescribed fire may reduce the frequency, geographic scale and intensity of natural wildfires, such that vistas in Class I areas will be clearer on more days of the year, to the enjoyment of visitors. States may also consider how the use of prescribed fire on wildland can benefit ecosystem health, protect public health from the air quality impacts of catastrophic wildfires and protect against other risks from catastrophic wildfires. These final rule revisions give states that have considered these factors, and other relevant factors, the flexibility to provide and plan for the use of prescribed fire, with basic smoke management practices applied, to an extent and in a manner that states and the EPA believe appropriate. The EPA is committed to working with states, tribes, federal land managers, other stakeholders and other federal agencies on matters concerning the use of prescribed fire, as appropriate, to reduce the impact of wildland fire emissions on visibility.

3. Final Rule

We are finalizing the fire-related definitions as proposed, including the revision of the definition of "fire" in 40 CFR 51.309(b)(4), with one change from proposal. We are finalizing a different definition of "wildfire" than we proposed. The final revised definition of a wildfire includes "a prescribed fire that has developed into a wildfire" instead of the proposed language "a prescribed fire that has been declared to be a wildfire." Two comments in this rulemaking objected to or asked for clarification of the meaning of the "declared to be a wildfire" portion of the definition. The definition of wildfire being finalized for the RHR in this final action is the same definition as recently finalized for the revised Exceptional Events Rule, as commenters in both rulemakings raised similar concerns about the proposed definition. Consistent with the approach taken in the final revised Exceptional Events Rule, we concluded that whether a prescribed fire should be treated as a wildfire for regional haze program purposes depends on the facts of the situation. Specifically, the final definition includes the phrase "a prescribed fire that has developed into a wildfire," which means a prescribed fire that has "developed in an unplanned way such that its management challenges are essentially the same as if it had been initiated by an unplanned ignition.'' *See* 81 FR 68250. While we proposed, and are finalizing, a definition of "wildfire" that includes a statement that a wildfire that predominantly occurs on wildland is a natural event, we do not intend to restrict a wildfire on other types of land from also being treated as a natural event or source, based on specific facts about the wildfire.

We are also finalizing 40 CFR 51.308(f)(3)(ii) as proposed to provide an adjustment to the URP framework for the 20 percent most impaired days due to the impacts of wildland fire conducted with the objective to establish, restore and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species for purposes of ecosystem health and public safety during which appropriate basic smoke management practices were applied. Such an adjustment is not available for fires of any type on lands other than wildland or to burning on wildland that is for purposes of commercial logging slash disposal rather than wildland ecosystem health and public safety.

We are also finalizing the term "basic smoke management practices" as an update of the term "smoke management techniques" in 40 CFR 51.308(f)(2)(iv)(D) (renumbered). We are also finalizing the use of "smoke management programs" where the 1999 RHR used the term "plans." The final rule differs from the proposal in that it does not include the phrase "as currently exist within the State for these purposes."

This action also deletes the obsolete and duplicative definition of "base year" in 40 CFR 51.309(b)(8) and reserves that section number. The definition of "base year" in 40 CFR 51.309(b)(7) is the operative definition for this section of the RHR. The definition being deleted refers to 40 CFR 51.309(f) which is reserved in the current rule.

H. Clarification of and Changes to the Required Content of Progress Reports

1. Summary of Proposal

The proposed rule detailed additional revisions to 40 CFR 51.308(g) in order to clarify the substance of the regional haze progress reports, given ambiguities in the 1999 RHR with respect to, among other things, the period to be used for calculating current visibility conditions, and whether forward-looking, quantitative modeling is required in the progress reports to assess whether RPGs will be met. These proposed revisions were numerous and often independent of one another, and are summarized briefly as follows.

A proposed revision to the opening portion of 40 CFR 51.308(g) would have required that a state provide the public with a 60-day comment period on a draft progress report that is not a SIP revision, before submitting it to the EPA. The 1999 RHR did not explicitly say that a public comment period was required for progress reports, because other EPA rules require public notice for all SIP revisions and under the 1999 RHR progress reports have been SIP revisions.

Proposed revisions to 40 CFR 51.308(g)(3)(ii) added a number of explanatory sentences to better indicate what "current visibility conditions" are and how to calculate them, given that it is not clear what "current visibility conditions" are in the 1999 RHR. Practicality requires that "current conditions" should mean "conditions for the most recent period of available data."[121] The proposed text also made clear that the period for calculating current visibility conditions is the most recent rolling 5-year period for which IMPROVE data are available as of a date 6 months preceding the required date of the progress report, given our belief that (since we also proposed that progress reports no longer be submitted as SIP revisions) this period would be

[121] In our guidance on the preparation of progress reports, the EPA indicated that for "current visibility conditions," the reports should include the 5-year average that includes the most recent quality assured public data available at the time the state submits its 5-year progress report for public review. *See* section II.C of General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans, April 2013.

sufficient for states to incorporate the most recent available data into their progress reports.[122] We also invited comment on other specific appropriate timeframes, including 3 months, 9 months and 12 months.

Proposed revisions to 40 CFR 51.308(g)(3)(iii) were designed to remedy a gap in the 1999 RHR, which failed to make clear what the "past 5 years" are for assessing the change in visibility impairment. We proposed to delete the "past 5 years" text and replace it with text indicating the change in visibility impairment is to be assessed over the span of time since the period addressed in the most recent periodic comprehensive SIP revision. The EPA believed this would remedy the issue that, because of data reporting delays, the period covered by available monitoring data will not line up with the periods defined by the submission dates for progress reports, and would ensure that each year of visibility information is included either in a periodic comprehensive SIP revision or the progress report that follows it. We proposed to make the same change to the 1999 RHR's "past 5 years" text in the first sentence of 40 CFR 51.308(g)(4) for the purposes of reporting changes in emissions of pollutants contributing to visibility impairment, for similar reasons.

We proposed several other revisions, particularly to 40 CFR 51.308(g)(4), to revise and clarify the states' obligations regarding emissions inventories. One issue was that the 1999 RHR's text seemingly required a state to project emissions inventories to the end of the "applicable 5-year period" whenever that endpoint is not the year of a triennial inventory (2011, 2014, etc.) required by 40 CFR part 51 subpart A (Air Emissions Reporting Requirements). For a

[122] Note that we are not proposing this specification of 6 months for the progress report aspects of a periodic comprehensive SIP revision (*see* Section IV.E of this document), in light of the longer time needed for administrative steps between completion of technical work and submission to the EPA.

variety of reasons more fully explained in the preamble to our proposal, we proposed text changes that explain clearly that states must include in their progress reports the emissions, by sector, from all sources and activities up to the triennial year for which information has already been submitted to the NEI. With regard to emissions data for EGUs, states would need to include data up to the most recent year for which the EPA has provided a state-level summary of such EGU-reported data. Finally, the last sentence of the proposed text for 40 CFR 51.308(g)(4) made clear that if emission estimation methods have changed from one reporting year to the next, states need not backcast (i.e., use the newest methods to repeat the estimation of emissions in earlier years) in order to create a consistent trend line over the whole period, since although some states expressed concern that other parties may interpret the 1999 RHR as requiring it, the EPA has never expected states to backcast in this context.

We also proposed changes to 40 CFR 51.308(g)(5), which requires assessments of any significant changes in anthropogenic emissions that have occurred, consistent with our proposed changes to other sections. Specifically, we proposed to delete the reference to the “past 5 years” and instead direct states that the period to be assessed involves that since the last periodic comprehensive SIP revision. We also proposed text that would require states to report whether these changes were anticipated in the most recent SIP, given that this would assist the FLMs, the public and the EPA in understanding the significance of any change in emissions for the adequacy of the SIP to achieve established visibility improvement goals.

The EPA further proposed to renumber the 40 CFR 51.308(g)(6) of the 1999 RHR as 40 CFR 51.308(g)(7), and proposed to change that provision to clarify that the RPGs to be assessed are those established for the period covered by the most recent periodic comprehensive SIP revision. The proposed change did not alter the intended meaning of this section, and simply clarified that in a progress report, a state is not required to look forward to visibility conditions beyond the end of the current implementation period.

The proposed, new 40 CFR 51.308(g)(6) included a provision requiring a state with a long-term strategy that includes a smoke management program for prescribed fires on wildland to include in each required progress report a summary of the most recent periodic assessment of the smoke management program, including conclusions that were reached in the assessment as to whether the program is meeting its goals regarding improving ecosystem health and reducing the damaging effects of catastrophic wildfires.

A final proposed change to 40 CFR 51.308(g) removed the provisions of 40 CFR 51.308(g)(7) of the 1999 RHR entirely, relieving the state of the need to review its visibility monitoring strategy within the context of the progress report, a change that had been requested by many states during our pre-proposal consultations. Such a change was appropriate since all states currently rely on their participation in the IMPROVE monitoring program (and expect to continue to do so), so continuing the requirement for every state to submit a distinct monitoring strategy element in each progress report would consume state and EPA resources with little or no practical value for visibility protection.

Finally, we proposed minor changes to 40 CFR 51.308(h) and 40 CFR 51.308(i). Proposed changes to 40 CFR 51.308(h) regarding actions the state is required to take based on the progress report merely removed the implication that all progress reports are to be submitted at 5-year intervals, and aimed to improve public understanding of the declaration that a state must make when it determines that no SIP revisions are required. The proposed changes to 40 CFR 51.308(i) created a stand-alone requirement that states must consult with FLMs regarding progress reports because the 1999 RHR only applies FLM consultation requirements to SIP revisions (and the proposal would remove the formal SIP revision requirement from progress reports).

2. *Comments and Responses*

Several commenters pointed out that while there is no explicit provision in the 1999 RHR for the public to comment prior to the submission of progress reports for the first implementation period, which are required to be SIP revisions, other provisions in EPA rules require states to provide at least a 30-day notice to the public on any type of SIP revision, in contrast to the 60-day period we proposed to require for progress reports that are not SIP revisions. The commenters generally opposed the longer period and noted that it, in combination with the requirement to consult with FLMs well ahead of the start of public comment, would make it more difficult to meet the requirement that progress reports contain emissions and air quality information no older than 6 months. We agree that retaining the current requirement for a 30-day public comment period is appropriate and are finalizing that period. States may provide a longer comment period, either initially or upon request, and we recommend that states do so when it would not prevent timely submission to the EPA.

Some commenters opposed the proposed provision in 40 CFR 51.308(g)(3)(ii) making clear that the period for calculating current visibility conditions is the most recent rolling 5-year period for which IMPROVE data are available as of a date 6 months preceding the required date of the progress report. As discussed previously, we also invited comment on other specific timeframes, and most of these commenters felt 12 months to be a more appropriate timeframe. However, in general these comments pointed specifically to the proposed provision requiring consultation with FLMs 60 to 120 days prior to a public hearing or other public comment opportunity on progress reports, and/or pointed to the proposed requirement for a 60-day public comment opportunity, as the reason for a 12-month period for IMPROVE data availability. However, as noted elsewhere in this document these two review/comment periods are not being finalized as proposed. In addition, the argument of several commenters that 6 months is an insufficient period to incorporate IMPROVE data even without the extended FLM consultation period was not well supported. Therefore, the EPA does not find these comments persuasive given the other content of the final rule.

One commenter on the proposed 40 CFR 51.308(g)(3)(ii) noted that given the fact that progress reports for the first implementation period have often not been submitted on time, the EPA should adjust the language of the rule text such that the period for calculating current visibility conditions should be based on the later of the required date or submittal date of the progress report. The EPA disagrees with this assessment because this could create a situation requiring a state to re-analyze data (and substantially re-draft portions of a progress report) in situations where submittal of a progress report is delayed for valid or unforeseeable reasons. We note that there will be other avenues for the public and the EPA to obtain the most recent IMPROVE data if a late progress report does not have the most current information.

Comments on the proposed revisions to 40 CFR 51.308(g)(4) regarding emissions tracking were numerous and varied, with many commenters expressing reservations about the proposed text. In general, these commenters asked that the EPA either not require states to use NEI data unless such data are available in final form a minimum of 12 months prior to the due date of the progress report, or that states should use the most recent final NEI data available at the time the progress report is prepared. In response, we want to reiterate that our proposal addressed only the requirement for the time period for the emissions information to be included in a progress report. We did not propose to require that the emissions data actually submitted to or contained in any version of the NEI be used in a progress report. Our intention is that a state have the flexibility to update and revise such data prior to presenting it in a progress report, but not the flexibility to limit its presentation to only emissions information for earlier years.[123] Second, we acknowledge that, as proposed, this subsection could be interpreted to trigger a requirement to present emissions data for a certain year should data for that year be made available for the first time the day before the planned submission of a progress report. We are therefore finalizing additional text in 40 CFR 51.308(g)(4) (similar to text proposed and being finalized in 40 CFR 51.308(g)(3)) making clear that only NEI emissions data submitted by the state to the Administrator (or, in the case of data submitted directly by sources to a centralized emissions data system, made available in a state-level summary by the Administrator) at least 6 months prior to the due date for the progress report triggers the requirement that the progress report include emissions information for that year.

Proposed changes to 40 CFR 51.308(g)(5) involving assessments of any significant changes in anthropogenic emissions that have occurred since the period addressed in the last SIP revision were generally well received, however, one commenter asked that the EPA require additional specificity in this assessment. The EPA did not make any changes in response to this comment because the rule we are finalizing already includes the required information.

Comments on the proposed, new 40 CFR 51.308(g)(6) regarding a progress report including a summary of the most recent periodic assessment of any existing smoke management program that is part of the long-term strategy were numerous, with some commenters generally

[123] This point about updating and revising data for a particular year also applies to emissions information made available by the Administrator in a state-level summary. It is possible that a state may have more recent, more complete or more accurate data for its sources than the Administrator has been able to include in his or her state-level summary for a particular year.

favoring and all but one state opposing this additional rule provision. The comments in opposition to the new provision appear to interpret it as creating a requirement that states periodically assess their smoke management programs and whether these programs are meeting their goals. However, the proposed provision was not intended to create any such requirement. It merely intended that if there is a smoke management program in the long-term strategy that already has a periodic program assessment element, the findings and recommendation of the most recent assessment must be summarized in the regional haze progress report. We are finalizing small changes from the proposed provision to make this intention clear. We reiterate that we interpret this provision to only apply to smoke management programs that have been made part of the long-term strategy in the regional haze SIP, and only to programs that have a program evaluation element. A state that has such a smoke management program and has included its program in its regional haze SIP has acknowledged that management of smoke is a significant concern with respect to visibility. Providing the public with easy access to a summary of the most recent program assessment via the regional haze progress report will facilitate public participation in the state's development of its next SIP revision. The benefit of including a summary of the program assessment for a smoke management program that is not part of the SIP in the progress report, if there has been a program assessment, may be less, and we believe a state should have flexibility to include or not include such a summary in its progress report.

Regarding the proposed 40 CFR 51.308(g)(7) (which as proposed was simply a modified version of the 1999 RHR's 40 CFR 51.308(g)(6) that clarified that a progress report's required assessment of whether a SIP is sufficient to meet established RPGs should address the RPGs defined for the end of the particular implementation period), the few comments received from states indicated a general opposition to the requirement to evaluate SIP adequacy to meet RPGs.

The EPA did not propose to remove this function of the progress reports, so comments in favor of removing it are outside the scope of this rulemaking.

The proposed removal of the provisions of the 1999 RHR's 40 CFR 51.308(g)(7), designed to relieve the state of the need to review its visibility monitoring strategy within the context of the progress report, received few comments, but was generally opposed by conservation organization commenters and favored by state commenters. With respect to the progress reports that will be due in the second and subsequent implementation period, the reasoning for eliminating these provisions as explained in the proposal remains valid even in light of the comments received. However, upon further consideration it is appropriate to leave in place the requirement for a monitoring strategy element for the remaining progress reports due in the first implementation period, as many progress reports have already been submitted and many others are well under development. Being consistent with respect to this requirement for all progress reports during the first implementation period will not be a significant burden on the states. We have not disapproved the monitoring strategy element of any progress report to date.

The RTC responds to these comments in more detail.

Public comments on 40 CFR 51.308(i) regarding the requirement for consultation with FLMs on progress reports are discussed elsewhere in this document.

3. Final Rule

The EPA is finalizing all of the rule text detailed in the preceding discussion as proposed with changes. Instead of removing the 1999 RHR's 40 CFR 51.308(g)(7) regarding monitoring strategies entirely, we are retaining it but making it applicable only to progress reports for the first implementation period. With the retention of 40 CFR 51.308(g)(7), the numbering of other sections in the final rule is different than proposed and is consistent with the numbering in the

1999 RHR. We are revising the opening text of 40 CFR 51.308(g) to make the required public comment period be 30 days rather than 60 days. We are revising 40 CFR 51.308(g)(4) to provide a 6-month grace period for the trigger of the requirement to include emissions information for a recent year. The final version of new 40 CFR 51.308(g)(8) (numbered as (g)(6) in the proposal) has been revised from the proposal to clarify its applicability.

We are finalizing rule text in 40 CFR 51.308(g)(7) that makes it clear that all remaining progress reports for the first implementation period submitted after these rule revisions are finalized must address the monitoring strategy, as has been the requirement of the 1999 RHR for progress reports already submitted. A progress report for the second or a subsequent implementation period will not have to address the monitoring strategy.

I. Changes to Reasonably Attributable Visibility Impairment Provisions

1. Summary of Proposal

The EPA proposed extensive changes to 40 CFR 51.300 through 51.308 with regard to reasonably attributable visibility impairment. The motivation for these changes was discussed in detail in the proposal. In summary, in the time since the reasonably attributable visibility impairment provisions were originally promulgated in 1980, advances in ambient monitoring, emissions quantification, emission control technology and meteorological and air quality modeling have been built into the regional haze program, such that state compliance with the RHR's requirements will largely ensure that progress is made towards the goal of natural visibility conditions. Therefore, some aspects of the reasonably attributable visibility impairment provisions of the visibility regulations have less potential benefit than they did when they originally took effect. These provisions have received few revisions over the years resulting in a substantial amount of confusing and outdated language within the current visibility regulations including seemingly overlapping and redundant requirements. While there have historically been very few certifications of existing reasonably attributable visibility impairment by an FLM, in several situations a certification by an FLM has ultimately resulted in new controls or changes in source operation.

The EPA therefore proposed to (1) eliminate recurring requirements on states that we believe have no significant benefit for visibility protection; (2) clarify and strengthen the 1999 RHR's provisions under which states must address reasonably attributable visibility impairment when an FLM certifies that such impairment is occurring in a particular Class I area due to a single source or a small number of sources; (3) remove FIP provisions that require the EPA to periodically assess whether reasonably attributable visibility impairment is occurring and to respond to FLM certifications; and (4) edit various portions of 40 CFR 51.300 through 40 CFR 51.308 to make them clearer and more compatible with each other. The EPA solicited comment on each of the proposed changes as well as suggestions for alternative approaches.

Specific proposed provisions included:

- Revisions to 40 CFR 51.300, Purpose and applicability, to expand the reasonably attributable visibility impairment requirements to all states in light of the evolved understanding that pollutants emitted from one or a small number of sources can affect Class I areas many miles away.
- Revisions to 40 CFR 51.301, Definitions, to change the definition of *reasonably attributable* in order to make clear that a state does not have complete discretion

to determine what techniques are appropriate for attributing visibility impairment to specific sources.

- Deletion of the entire text of 40 CFR 51.302 and replacement with new language clearly describing a state's responsibilities upon receiving a FLM certification of reasonably attributable visibility impairment. The following aspects of the proposed 40 CFR 51.302 are of particular relevance in summarizing comments and explaining our final action.
  - The proposed 40 CFR 51.302(b) described the required state action in response to any FLM certification of reasonably attributable visibility impairment, namely that a state shall revise its regional haze implementation plan to include a determination, based on the four reasonable progress factors set forth in 40 CFR 51.308(d)(1)(i)(A), of any controls necessary on the certified source(s) to make reasonable progress toward natural visibility conditions in the affected Class I area. This would preserve the existing state obligation, including the fact that a certification by an FLM would not create a definite state obligation to adopt a new control requirement, but rather only to submit a SIP revision that provides for any controls necessary for reasonable progress. It would be the EPA, not the certifying FLM, that would determine whether the responding SIP is adequate and the response reasonable.
  - The proposed 40 CFR 51.302(c) addressed those situations where an FLM certifies as a reasonably attributable visibility impairment source a BART-eligible source where there is at that time no SIP or FIP in place setting

BART emission limits for that source or addressing BART requirements via a better-than-BART alternative program.[124] In such an instance, the proposed rule would require the state to revise its regional haze SIP to meet the requirements of 40 CFR 51.308(e), BART requirements for regional haze visibility impairment, and notes that this requirement exists in addition to the requirements of 40 CFR 51.302(b) regarding imposition of controls for reasonable progress. The proposed version of 40 CFR 51.302(c) also clarified two aspects of the 1999 RHR to match the EPA's past and current interpretations. First, while a certification of reasonably attributable visibility impairment for a BART-eligible source prior to the EPA's approval of a state's BART SIP for that source does not impose any substantive obligation on a state that is over and above the BART obligation imposed by 40 CFR 51.308, the state's response to the certification of reasonably attributable visibility impairment for a BART-eligible source must take into account current information. Second, a certification of reasonably attributable visibility impairment for a BART-eligible source after the state's BART SIP for that source has been approved by the EPA does not trigger a requirement for a new BART determination based on the five statutory factors for BART, but rather, the

[124] Although most of the BART requirements have been addressed in most states, there remain a handful of states with BART obligations. In addition, there is litigation over the BART element in some approved SIPs and promulgated FIPs. We expect that this situation may exist in one or more states at some time after the effective date of the final rule.

state's obligation with respect to that source is the same as for a non-BART eligible source.

  - Three alternatives were proposed for 40 CFR 51.302(d) regarding the time schedule for state response to an FLM certification of reasonably attributable visibility impairment.

- Revisions to 40 CFR 51.303, Exemptions from control, to correctly refer to the new 40 CFR 51.302(c) as well as to the BART provisions in 40 CFR 51.308(e). Note that these revisions were described in the preamble of the proposal, but were inadvertently not included in the proposed rule text.
- Revisions to 40 CFR 51.304, Identification of integral vistas, to remove antiquated language in light of the fact that FLMs were required to identify any such integral vistas on or before December 31, 1985, and to list those few integral vistas that were properly identified.
- Revisions to 40 CFR 51.305, Monitoring for reasonably attributable visibility impairment, to state that the requirement to include in a periodic comprehensive SIP revision a monitoring strategy specifically for reasonably attributable visibility impairment in Class I area(s) only applies in situations where the Administrator, Regional Administrator or FLM has advised the state of a need for it.
- Complete removal of 40 CFR 51.306.
- Revisions to 40 CFR 51.308 (in addition to those discussed elsewhere in this document and in the proposal) related to reasonably attributable visibility impairment.

- Revisions to 40 CFR 51.308(e), BART, relating to a state's option to enact an emissions trading program or other alternative measure in lieu of source-specific BART.

Finally, consistent with our proposal to remove the requirement for states to periodically assess reasonably attributable visibility impairment, the EPA proposed to revise many sections of 40 CFR part 52 to remove provisions that establish FIPs that require the EPA to periodically assess whether reasonably attributable visibility impairment exists at Class I areas in certain states and to address it if it does, and to respond to any certification of reasonably attributable visibility impairment that may be directed to a state that does not have an approved reasonably attributable visibility impairment SIP.

2. Comments and Responses

Comments on the proposed revisions to 40 CFR 51.300 regarding the expansion of reasonably attributable visibility impairment to states that do not have Class I areas were mixed across stakeholder groups. While few commenters expressed disagreement with the EPA's statements surrounding the improved scientific understanding of long-range pollutant transport showing that reasonably attributable visibility impairment can be an interstate issue, commenters opposing the reasonably attributable visibility impairment expansion generally pointed to the alleged redundant nature of the reasonably attributable visibility impairment and regional haze requirements, as well as asserting that any and all FLM concerns can be raised during the SIP development process. Using similar arguments, a number of commenters urged the EPA to remove the reasonably attributable visibility impairment requirements entirely, although this was not an option outlined in the proposal.

A number of comments on the proposed revisions to 40 CFR 51.301 regarding definitions opined that changing the definition of “reasonably attributable” (to remove implied state discretion in determining whether the technique used was appropriate) would significantly alter the federal-state relationship in the visibility program and give FLMs authority beyond that afforded in sections 169A and 169B of the CAA. In response, the EPA is clarifying that the text edit to remove the phrase “the state deems” from the definition of “reasonably attributable” was not intended to give the FLMs sole power to determine what technique is appropriate for attributing visibility impairment to a source or small number of sources. If and when an FLM makes a certification, it can base the certification on a technique that it thinks appropriate. Whether that technique is appropriate is an issue that the affected state may opine on during the consultation opportunity the FLM is required to offer (details of this consultation opportunity are discussed later) and as part of its responsive SIP revision. If the state believes that the technique is not appropriate and that no appropriate technique would verify the attribution alleged by the FLM, the state may submit a narrative-only SIP revision that disagrees with the certification and explains the reason for the disagreement, and accordingly contains no additional measures for the identified source or sources. However, it will be the EPA that ultimately determines whether the technique was appropriate, when we approve or disapprove the responsive SIP revision after considering the information that supports the certification, the information in the SIP revision, and public comments. This change in the rule text does not alter the federal-state relationship, because even under the wording of the 1999 RHR, the EPA would review the reasonableness of a state’s determination as to what technique is appropriate for attributing visibility impairment.

Several of these comments also ask that, if the EPA finalizes this change in definition, that the scope of attribution techniques which would qualify as “appropriate” be better stated. On this point, the EPA does not believe imposing such limits on the scope of techniques that qualify as "appropriate" is justified, particularly given that continually improving scientific understanding of pollutant transport and the continually evolving scope of modeling will no doubt result in even better attribution techniques in the future.

Other comments on 40 CFR 51.301 asked for a more descriptive and thorough definition of "reasonably attributable visibility impairment" and its related terms. Comments on 40 CFR 51.302 regarding FLM certification of reasonably attributable visibility impairment contained similar requests, with most states and industry expressing concern that the proposed rule did not define sufficiently limiting principles for FLMs, failed to identify information about the scientific basis for any certification of reasonably attributable visibility impairment, and did not provide any basis by which a state or source could review or object to any certification of reasonably attributable visibility impairment before it triggered a mandatory obligation to respond. Several commenters asked for guidance or criteria in the final rule for the certification process and techniques for attribution, with some providing a suggested list of elements to include in a certification of reasonably attributable visibility impairment.

The comments in favor of a more specific provision in the final rule for what type of source impact, assessed by what method, constitutes reasonable attributable visibility impairment did not offer any particular more specific definition of reasonably attributable visibility impairment, and we had not proposed any more specific definition. While the EPA acknowledges the comments, we do not think it is necessary to finalize a more specific definition in the rule text. The EPA agrees with the portion of one comment letter suggesting that a thorough certification of reasonably attributable visibility impairment should describe the location(s) within the Class I area where the impairment occurs, when (e.g., year-round or only during certain times of the year) the impairment occurs, what attribution methods were used to determine impairment (such as photographs or videos, monitoring, and/or modeling), a description of how the impairment adversely impacts visibility, an identification of the source or sources believed by the FLM to be causing the impairment and the methods used to make this determination. Past reasonably attributable visibility impairment certifications have generally included these elements or the certifying FLM otherwise shared such information with the state.

Additional comments on 40 CFR 51.302 asked for some degree of state participation in certification development, such as a pre-certification consultation requirement whereby FLMs must consult with states (and possibly EPA) before certifying, as well as an option for the state to appeal a certification once received. In response to these comments, we are including a consultation obligation on the FLMs in the final rule text. We would like to reiterate the importance of state-FLM consultation for all aspects of the RHR, including reasonably attributable visibility impairment. While the final rule requires the FLM to offer a state an in-person consultation meeting at least 60 days prior to making a certification of reasonably attributable visibility impairment, we encourage FLMs and state to have conversations and exchange technical information even earlier. The FLMs have conveyed to the EPA their expectation that a reasonably attributable visibility impairment certification will be an unusual "backstop" for a situation that is not otherwise addressed under the regional haze program despite good communication between the FLM and the state. In addition, in each instance since the original regulations were promulgated since 1980, FLMs have consulted with states and EPA and only made the decision to certify reasonably attributable visibility impairment when these conversations did not lead to a resolution of the issue.

One commenter said that there is no provision in the 1980 rule on reasonably attributable visibility impairment that allows an FLM to make a certification for a source that is not BART-eligible. This commenter objected to the explicit provisions in our proposed rule revisions that provide for such a certification. We disagree with the commenter's description of the 1980 rule. We recognize that the term "existing stationary facility" was defined in the 1980 rule as including only BART-eligible sources, and that many of the provisions of the 1980 rule were specific to these sources. However, the 1980 rule's definition of reasonably attributable visibility impairment refers to "air pollutants from one, or a small number of sources," not more narrowly to "existing stationary facilities." Also, 40 CFR 51.302(c)(2)(i) as promulgated in 1980 says that a state plan to address reasonably attributable visibility impairment must include a strategy "as may be necessary to make reasonable progress towards the national goal" and 40 CFR 51.302(c)(2)(ii) requires an assessment of how each element of the plan relates to preventing visibility impairment. Neither of these sections is limited to only "existing stationary facilities." In addition, 40 CFR 51.302(c)(3) as promulgated in 1980 required plans to require "each source" to maintain control equipment and to establish procedures to ensure the equipment is properly operated and maintained. While the remaining parts of 40 CFR 51.302(c) contain more specific requirements that apply when a certification of reasonably attributable visibility impairment has identified an "existing stationary facility", the existence of these requirements does not mean that an FLM may not make a certification for another type of source or that a state has no obligation to submit a SIP revision to respond to the certification. Furthermore, as explained in more detail in the RTC, we believe that the CAA provides broad enough authority for the EPA to promulgate the provisions in the final rule regarding the certification of reasonably attributable visibility impairment by sources that are not BART-eligible, regardless of how these sources were addressed in the 1980 rule. If a certification is made for a source (or a small number of sources) that is not BART-eligible (or for a BART-eligible source for which the EPA has already approved or promulgated a plan addressing the BART requirement), the responsive SIP revision must provide for whatever measures for that source are necessary to make reasonable progress considering the four statutory factors, unless the SIP revision establishes that there is no reasonably attributable visibility impairment due to the identified source.

There were a number of comments on 40 CFR 51.302(d) regarding the proposed three options for a schedule for state response to a certification of reasonably attributable visibility impairment. Some commenters recommended the first proposed approach of keeping the 1999 RHR's schedule under which a state response is due within 3 years of a certification of reasonably attributable visibility impairment. Most commenters found the third proposed approach to be unnecessarily complicated, while some objected to how much time could elapse between a certification and the state's responsive SIP revision; we are not finalizing the third approach and will not discuss it further. Some commenters favored a modified version of the second proposed option (in which the deadline would be the earlier of the due date for the next progress report or periodic comprehensive SIP revision, so long as that submission is due at least 2 years after the certification), but with more time to respond. These commenters generally stated that the minimum workable time was either 3 or 4 years. It is noteworthy, however, that other commenters opposed this second option, largely due to the fact that in some situations a state response would not be due for some time after an FLM certification (up to 7 years).

We noted that if the second approach were finalized but with the minimum time to respond to a certification increased to 3 or 4 years (as recommended by some states), responses to FLM certifications may not be due until 8 or 9 years after certification, which is an excessive amount of time. The EPA believes that retaining the fixed 3-year deadline of the existing rule is workable for all parties and is most appropriate and hence is finalizing the first option in this rulemaking, with an added provision that no response will be due before the July 31, 2021, due date of the next SIP revision.[125] While not specifically proposed, this provision is being finalized in response to the general concern of some commenters with a state having to respond to a reasonably attributable visibility impairment certification before it has had an opportunity to systematically consider what additional emission reductions measures are necessary for reasonable progress for the second implementation period taking into account all the requirements of this final rule.

While we did not publish specific proposed rule changes for removing all mention of integral vistas from the visibility protection rules, we invited comment on such a step. We did so because it appeared that if we finalized our other proposals, there would be no requirement in our rules that actually depends on whether an integral vista associated with a Class I area had been identified. Thus, removing mention of integral vistas would simplify the rule text without changing any party's obligations under our visibility protection rules. A number of commenters agreed with our assessment and supported the removal of all mention of integral vistas, and no commenter opposed this change. However, we now realize that because the definition in 40 CFR 51.301 that "*visibility in any mandatory Class I Federal area* includes any integral vista associated with that area" and because there are several provisions that after our final action continue to use the term "visibility in any mandatory Class I Federal area," there are some

[125] The added provision that refers to July 31, 2021, will have the effect of providing additional time for the state's response only for a reasonably attributable visibility impairment certification made prior to July 31, 2018.

provisions where the existence of a single identified integral vista could conceivably make a difference to the obligation of some party or to an EPA action. For this reason, we are finalizing only what we proposed, which is removal of antiquated language in section 40 CFR 51.304, but not removal of all references to integral vistas in subpart P.

For a discussion of the comments on other areas proposed and being finalized related to reasonably attributable visibility impairment, please *see* the RTC document available in the docket for this rulemaking.

3. Final Rule

We are finalizing the proposed revisions to the reasonably attributable visibility impairment and related provisions, with four changes.

First, as mentioned in the Section IV.I.2 of this document, we are finalizing a modified version of one of the proposed alternatives regarding the deadline for state response to a certification of reasonably attributable visibility impairment certification, namely that the response would always be due within 3 years (as required by the existing rule). The final rule retains this option's 3-year, fixed deadline rather than one of the alternative schemes proposed that would have always aligned the deadline with the next SIP revision or progress report, but adds an additional one-time provision such that a state response to a certification of reasonably attributable visibility impairment will in no case be due earlier than July 31, 2021. The final rule retains the language indicating that the state is not required at the time of response to also revise its RPGs to reflect the additional emission reductions required from the source or sources.

Second, we are adding to 40 CFR 51.308(e)(2)(v) and 40 CFR 51.308(e)(4) references to the reasonably attributable visibility impairment provisions in 40 CFR 51.302(b) and 40 CFR 51.302(c). We proposed to add to each of these parts of the rule only a reference to 40 CFR

51.302(b) but have realized that a reference in each to 40 CFR 51.302(c) is also needed. With these revisions, it is clear that for a BART-eligible source participating in a trading program that has been determined to be better-than-BART, if an FLM certifies that there is reasonably attributable visibility impairment due to that source a state may include a geographic enhancement of the trading program to satisfy both the reasonable progress obligation under 40 CFR 51.302(b) and any outstanding BART obligation under 40 CFR 51.302(c). While most BART-eligible sources cannot become subject to 40 CFR 51.302(c) because an approved BART SIP (or a SIP under 40 CFR 51.309) or a FIP is in place as a result of planning efforts in the first implementation period, there are a small number of BART-eligible sources that might become subject to 40 CFR 51.302(c) and it is important to be clear that a geographic enhancement is an option for them, as it has been under the 1999 RHR.

Third, also mentioned in the preceding section, we are finalizing a requirement in 40 CFR 51.302(a) that the FLM making a certification of reasonably attributable visibility impairment must offer an opportunity to the state(s) containing the identified sources to consult regarding the basis for the certification, in person and at least 60 days before the FLM makes the certification. This change was added in response to comments received that specifically asked for such consultation.

Fourth, we are not finalizing the proposed changes to 40 CFR 51.308(c), for the following reasons. Because we are finalizing a 3-year, fixed deadline for state response to a certification of reasonably attributable visibility impairment, the first part of the proposed provision (regarding the need to respond as part of an upcoming, otherwise due SIP revision) no longer applies. As to the second part of the proposed provision (regarding monitoring to assess reasonably attributable visibility impairment), we now realize this aspect is adequately covered by 40 CFR 51.308(f)(4) and that duplication of requirements in different subsections would only cause confusion. Therefore, 40 CFR 51.308(c) will remain unchanged from the 1999 RHR.

J. Consistency Revisions Related to Permitting of New and Modified Major Sources

1. Summary of Proposal

Proposed changes to 40 CFR 51.307, New source review, were limited to a few proposed changes to maintain consistency with other sections of the RHR and with the CAA. These changes were minor and therefore will not be repeated here.

2. Comments and Responses

There were no significant comments received on the proposed changes to this subsection.

3. Final Rule

Changes to 40 CFR 51.307 are being finalized as proposed. The EPA does wish to emphasize the requirement for FLM consultation during the new source review permitting process. As discussed in the preamble for the proposal, 40 CFR 51.307(a) requires FLM consultation for any new major source or major modification that would be constructed in an area designated attainment or unclassifiable that may affect visibility in any Federal Class I area. FLM consultation is also required under 40 CFR 51.307(b)(2) for any major source or major modification that proposes to locate in a nonattainment area that may affect visibility in any mandatory Federal Class I area. Two EPA guidance documents interpret this consultation requirement, particularly with regard to evaluating whether a proposed new major source or major modification may affect visibility in a Federal Class I area.[126] The EPA regional offices

[126] Notification to Federal Land Manager Under Section 165 (d) of the Clean Air Act, memo from David G. Hawkins, EPA Assistant Administrator for Air, Noise, and Radiation to EPA's Regional Administrators, March 19, 1979; 1990 New Source Review Workshop Manual, Chapter E, Section III A. Source Applicability.

can provide additional assistance to states in ensuring that their permitting programs meet the regulations and that the appropriate consultation is being conducted for affected permits.

K. Changes to FLM Consultation Requirements

1. Summary of Proposal

As discussed in the proposed rule, state consultation with FLMs is a critical part of the development of quality SIPs. We proposed not only to apply the FLM consultation requirements of 40 CFR 51.308(i)(2) to progress reports that are not SIP revisions, but to make further edits to this subsection to support such consultations. The proposed changes were motivated by a concern that the 1999 RHR's requirement for consultation at least 60 days prior to a public hearing may not result in a state offering an in-person consultation meeting sufficiently early in the state's planning process to meaningfully inform the state's development of the long-term strategy. We proposed to add a requirement that such consultation on SIPs and progress reports occur early enough to allow the state time for full consideration of FLM input, but no fewer than 60 days prior to a public hearing or other public comment opportunity. A consultation opportunity that takes place no less than 120 days prior to a public hearing or other public comment opportunity would then be deemed to have been "early enough."

2. *Comments and Responses*

Overall, the comments were split with many favoring any enhanced FLM participation in regional haze planning, while most states generally disfavored enhanced participation.

Regarding comments specific to the proposed changes to 40 CFR 51.308(i)(2), states were split in supporting or opposing the inclusion of a reference using the phrase "early enough." Some commenters said the criteria were not clear and asked for clarity on what would be needed to satisfy the requirement. In addition, many states and industry said the current 60-day period is long enough for SIPs, and that a longer period could delay their submission.

For progress reports, several state and industry commenters indicated that the 60-day period described in the 1999 RHR is sufficient, or that FLMs should not be consulted on progress reports at all if they are no longer required to be SIP revisions. A main concern was that anything more than a 60-day period would conflict with the proposed requirement in 40 CFR 51.308(g)(3) to assess current conditions based on the IMPROVE data available 6 months before the progress report due date. As discussed earlier in this document, this requirement under 40 CFR 51.308(g)(3) is being finalized as proposed. The EPA agrees that a requirement to consult with FLMs on progress reports more than 60 days prior to opening a public comment period may interfere with the revised provisions in 40 CFR 51.308(g)(3) and is therefore finalizing the 60-day requirement without referring to consultation being "early enough" and without referring to the 120-day point in the process.

Finally, some multi-state organization commenters asked for confirmation that state and FLM participation in the RPO process would continue to meet the consultation requirement. The EPA does not agree that such participation would suffice for consultation because being informed of the technical work performed by the multi-state organizations is not the same as the FLMs being substantively involved in regulatory decisions a state makes on what controls to require based on that work (i.e., the decisions on the long-term strategy on which public comment will be sought prior to submission to the EPA in the form of a SIP revision). Furthermore, the objective of these provisions is not to achieve FLM consultation with states on setting RPGs, since that process is largely mechanical in nature because RPGs are to be based on the long-term strategy and do not involve any additional policy decisions. We note that a standing invitation for FLM participation in the work performed by multi-state organizations may be part of the procedures that a SIP provides for continuing consultation between the state and the FLM, as required by 40 CFR 51.308(i)(4).

For a more thorough discussion of the comments on FLM consultation requirements, please *see* the RTC document available in the docket for this rulemaking.

3. Final Rule

After consideration of public comments, we are finalizing the revisions to 40 CFR 51.308(i)(2) with changes from proposal. The proposed requirement for consultation no fewer than 60 days prior to a public hearing or other public comment opportunity (with a consultation opportunity that takes place no less than 120 days prior to a public hearing or other public comment opportunity being deemed "early enough") is being finalized for SIP revisions. For progress reports (which, as discussed elsewhere in this document, will no longer be subject to the formalities of a SIP revision), the EPA is finalizing a requirement for consultation no fewer than 60 days prior to a public hearing or other public comment opportunity, with no reference to the consultation opportunity being "early enough." We are also finalizing somewhat different wording regarding the purpose of the consultation on SIP revisions, to convey the idea that consultation that takes place via an in-person meeting 60 to 120 days prior to a public hearing or comment opportunity will be about decisions that are about to be made by the state on its long-term strategy rather than about the plan for the technical analysis that informs these decisions, because by that time the technical analysis will have already been largely completed.[127] The final

[127] We expect that the FLM would have already provided input into the planning of the technical analysis including steps to gather information to be analyzed, as part of the ongoing consultation required under 40 CFR 51.308(h)(4) and as part of FLM participation in multi-state planning groups.

wording on the purpose of the consultation also emphasizes the content of the long-term strategy rather than the setting of the RPGs, consistent with the concept that the RPGs are a reflection of the requirements of the long-term strategy.

L. Extension of Next Regional Haze SIP Deadline from 2018 to 2021

1. Summary of Proposal

The EPA proposed to revise 40 CFR 51.308(f) to move the deadline for the submission of the next periodic comprehensive SIP revisions from July 31, 2018, to July 31, 2021, with states retaining the option of submitting their SIP revisions before July 31, 2021. We proposed to leave the end date for the second implementation period at 2028, regardless of when SIP revisions are submitted. The proposed change was to be a one-time schedule adjustment such that the due dates for periodic comprehensive SIP revisions for the third and subsequent planning periods would still be due on July 31, 2028, and every 10 years thereafter. The EPA proposed this extension to allow states to coordinate regional haze planning with other regulatory programs, including but not limited to the Mercury and Air Toxics Standards,[128] the 2010 1-hour SO_2 NAAQS,[129] the 2012 annual $PM_{2.5}$ NAAQS[130] and the Clean Power Plan,[131] with the further expectation that this cross-program coordination would lead to better overall policies and enhanced environmental protection.

2. Comments and Reponses

---

[128] 77 FR 9304, February 16, 2012.
[129] 75 FR 35520, June 22, 2010.
[130] 78 FR 3086, January 15, 2013.
[131] 80 FR 64,662, October 23, 2015. The Clean Power Plan was stayed by the Supreme Court for the duration of litigation. Order in Pending Case, *West Virginia v. EPA*, No. 15A773 (February 9, 2016). As a result, states have no compliance obligations with respect to the Clean Power Plan at this time.

Many commenters, especially state air agencies, expressed support for this extension, while other commenters opposed it. A primary concern from the latter group of commenters was that, given the fact that many initial regional haze SIPs were submitted late (in some cases, well into the first implementation period), this pattern was likely to continue and many periodic comprehensive SIP revisions would not be submitted by July 31, 2021, which would leave even less time during the second implementation period for any emission reductions necessary for reasonable progress to occur. One commenter stated that the 2021 date would be workable provided EPA acts promptly on each state's periodic comprehensive SIP revision, and that EPA should indicate now that it will make prompt findings of nonsubmittal or substantial inadequacy when the time comes.

As a general matter, making findings of nonsubmittal or substantial inadequacy are well within the EPA's authority. While we recognize the commenter's concern regarding the timing of SIP submissions, we expect that the length of the second implementation period will be sufficient to secure the emission reductions necessary for reasonable progress. The EPA anticipates that the experience states and the EPA have gained from the first round of regional haze planning will result in a more efficient process of SIP submission and review moving forward. Furthermore, the EPA has clarified in the final rule that whether or not a control measure can be installed and become operational before the end of the planning period is not a factor in determining whether that measure is necessary to achieve reasonable progress. Thus, the length of the implementation period should not be a barrier to achieving the emission reductions identified by the reasonable progress analysis. Finally, this rule change grants states additional time up front (before 2021) for regional haze planning and analysis and thus makes it more likely they will submit their SIP revisions for the second implementation period either on or ahead of schedule.

Some commenters contended that the EPA's rationales do not justify the proposed extension, and that giving states an additional 3 years to coordinate their planning would frustrate Congress's policy goals and impair human health. One commenter said that the EPA should evaluate the public health impacts of its proposal to delay the SIP deadline to 2021. We disagree with these comments. As we explained at proposal, the RHR requires states to include the impacts of other regulatory programs when developing their regional haze SIPs. Many industries, including the utility sector, are currently in the midst of developing mid- to long-term plans that will govern how they navigate the numerous recent additions to the regulatory landscape that include, but are not limited to, the programs discussed in the proposal and mentioned previously (i.e., the Mercury and Air Toxics Standards,[132] the 2010 1-hour SO_2 NAAQS,[133] the 2012 annual $PM_{2.5}$ NAAQS[134] and the Clean Power Plan).

Decisions that states and regulated entities make in response to one program may affect the options available for addressing their regional haze obligations, and vice versa. Providing time for regulated entities to coordinate their planning will allow them to design pollution control strategies that make efficient and effective use of their resources over the long term. Congress's goal of attaining natural visibility conditions will not be achieved in the next implementation period—it is necessarily a longer-term effort that will require states and regulated entities to make careful, considered decisions about how to balance the requirement to achieve sustained

---

[132] 77 FR 9304, February 16, 2012.
[133] 75 FR 35520, June 22, 2010.
[134] 78 FR 3086, January 15, 2013.

and sustainable visibility improvement moving forward with their business, regulatory and other priorities. Additionally, with the extension of the due date for the second implementation period SIPs, we are maintaining 2028 as the end date of the implementation period. We thus disagree that providing states 3 additional years to coordinate planning is inconsistent with continuing to make reasonable progress towards the ultimate goal of natural visibility conditions. We also disagree that providing 3 additional years will seriously undermine the goal of coordinated, regional planning among states. While we are aware that some states in the eastern U.S. are considering submitting SIPs before July 31, 2021, these states are coordinating among themselves on their technical analyses and they have not indicated that the extension will obstruct their coordination with other states.

Although Congress did not establish an explicit role for health considerations in the regional haze program, reductions of visibility-impairing pollutants also have important health related co-benefits. However, because the purpose of the regional haze program is improving visibility in Class I areas, we disagree that the EPA should evaluate the human health impacts of moving the deadline for regional haze SIP submissions from 2018 to 2021. Importantly, the emission reductions achieved in the first implementation period will continue to be in effect, and emissions will continue to be addressed during this period under the existing structure of federal, state and local clean air programs. Insofar as states and sources were already planning to undertake emission control projects in response to other regulatory requirements, the timing of these projects will be unaffected by the change in the SIP due date in the regional haze program. Furthermore, states are not required to wait until 2021 to submit their regional haze SIP revisions for the second implementation period, although they may choose to do so.

One commenter asserted that EPA's proposal to extend the deadline for submission of regional haze SIPs for the second implementation period violates the plain language of the section 169B(e)(2) of the CAA. The commenter argues that this statutory provision requires EPA to mandate that states submit regional haze SIP revisions within 12 months of promulgating RHR revisions under section 169A. We disagree. Section 169B(e)(2) states that "[a]ny regulations promulgated under section [169A] of this title pursuant to *this subsection* shall require affected States to revise within 12 months their implementation plans under section [110]." (emphasis added). The subsection at issue, 169B(e)(1), requires EPA to promulgate regional haze regulations within 18 months of receiving the report required of Visibility Transport Commissions under 169B(d)(2). This report was a one-time requirement intended to inform EPA's yet-to-be-promulgated regulations. Thus, section 169B(e)(1) clearly expresses Congress's intent to establish a timetable for the EPA's initial regional haze rulemaking in order to ensure that the regulations would be promulgated in a timely fashion and would be informed by the studies and report required under 169B(a)(1) and (d)(2), respectively. Section 169B(e)(2) states that regulations promulgated pursuant to (e)(1) – which addresses only EPA's obligation to undertake that initial regional haze rulemaking – must require states to submit SIP revisions within 12 months. We disagree with the commenter's assertion that Congress intended this 12-month deadline to apply in the case of subsequent rule revisions, as subsection (e) describes a one-time process of research, reports and rulemaking to get the regional haze program off the ground. Neither 169(e)(1) nor (e)(2) contains any indication that Congress intended this specific timeline to apply for additional, future rulemakings.

Another commenter said that in lieu of formally extending the deadline, the Agency should consider granting an administrative waiver to a state that affirmatively shows that a delay in submitting its periodic comprehensive SIP revisions is warranted. The EPA does not believe the additional effort required on the part of a state and the EPA would be worthwhile for such an undertaking because many states have good reason to coordinate their planning for their periodic comprehensive SIP revisions with that for other regulatory requirements and programs. A waiver process would thus add considerable administrative burden with minimal benefit, as the EPA would be likely to grant most or all of the waiver requests based on this need to coordinate planning.

3. Final Rule

The EPA is finalizing this one-time deadline extension with no changes from proposal.

M. Changes to Scheduling of Regional Haze Progress Reports

1. Summary of Proposal

The EPA proposed to revise the requirements in 40 CFR 51.308(g) and (h) regarding the timing of submission of reports evaluating progress towards the natural visibility goal. The 1999 RHR required states to submit regional haze progress reports every 5 years, with the first progress report due 5 years after submission of the first periodic comprehensive SIP revisions. Because states submitted these first SIP revisions on dates spread across several years, many of the due dates for progress reports currently do not fall mid-way between the due dates for periodic comprehensive SIP revisions, as the EPA initially envisioned. Looking forward, continued operation of the 1999 RHR would in many cases require a progress report shortly before or shortly after a periodic comprehensive SIP revision, at which time it could not be expected to have much utility as a mid-course review of environmental progress or much incremental informational value for the public compared to the data contained in that SIP revision.

Complementing the revisions to 40 CFR 51.308(f) regarding the deadlines for submittal of periodic comprehensive revisions, we proposed to revise 40 CFR 51.308 (g) and (h) such that the second and subsequent progress reports would be due by January 31, 2025, July 31, 2033, and every 10 years thereafter, placing one progress report mid-way between the due dates for periodic comprehensive SIP revisions. As we explained, this timing provides a balance between allowing the implementation of the most recent SIP revision to proceed long enough for a review to be possible and worthwhile, and having enough time remaining before the next comprehensive SIP revision for state action to make changes in its rules or implementation efforts, if necessary, separately from the actions in that next SIP.

As explained in the proposal, the EPA no longer believes a progress report is useful at or near the time of submission of a periodic comprehensive SIP revision, since in practical terms a progress report provides little additional information beyond that required in a periodic comprehensive SIP revision (with the exception of the 1999 RHR's requirement that a progress report include information on the trend in visibility over the whole period since the baseline period of 2000-2004). In order to substantially reduce administrative burdens and make progress reports more useful to the public with no attendant reduction in environmental protection, we proposed to limit the requirement for separate progress reports to the one due mid-way between periodic comprehensive SIP revisions and to add to the requirement for periodic comprehensive SIP revisions a requirement to include the visibility trend information that the 1999 RHR previously required exclusively in progress reports.

2. Comments and Responses

Commenters generally supported the change to progress report scheduling such that due dates would fall mid-way between those of periodic comprehensive SIP revisions, though some comments recommended that a periodic SIP revision be explicitly required to include all the required progress report elements listed in 40 CFR 51.308(g) of the 1999 RHR and in particular element (g)(6), which requires an assessment of whether the current SIP is sufficient to meet all established RPGs. There are seven listed progress report elements in the 1999 RHR and eight listed elements in the revised final rule. The subjects of the first five of the elements are the same in the two versions of the rule, and we proposed and are finalizing a requirement that each periodic SIP revision address these five elements. We are not requiring periodic SIP revisions to assess whether the SIP is sufficient to meet all established RPGs (element (g)(6) in the 1999 RHR and the revised final rule). Given that the SIP is being revised, there would be no utility in assessing whether the previous terms of the SIP for the previous implementation period were sufficient to meet the progress goals for the previous period. Also, since the new SIP revision will contain new progress goals for the end of the currently applicable implementation period and these goals will be calculated to reflect the new measures in that SIP revision and previously adopted measures, it necessarily will be that this revised SIP is sufficient to meet the new goals. The seventh element of a progress report as listed in the 1999 RHR (which EPA is eliminating in the revised rule for progress reports for the second and subsequent implementation periods for reasons described elsewhere in this document) is a review of the monitoring strategy. However, periodic SIP revisions are required to address the monitoring strategy under 40 CFR 308(f)(6) of the final rule text, so no further mention of monitoring strategies is needed. The newly added element of a progress report in the revised final rule (now numbered as element (g)(8)) is the summary of the most recent assessment of a smoke management program if any. Our reasons for not requiring periodic SIP revisions to include such a summary are given elsewhere in this document.

Some commenters requested that the progress report due January 1, 2025, be removed from the rule, given the fact that it would be due only 3.5 years after the July 31, 2021, due date of the next periodic comprehensive SIP revision. These commenters felt this time period prohibitively short and that this information could be better be included in the next periodic comprehensive SIP revision due July 31, 2028. A few commenters asked that EPA entirely remove the requirement for progress reports from the regional haze program. As noted previously, progress reports are an important tool for states to review and potentially make changes in their rules or implementation efforts, if necessary. Although the progress report for the second implementation period will be due only 3.5 years after the due date of the preceding periodic comprehensive SIP revisions, we still believe in the usefulness of such a mid-course review. In addition, some states have indicated that they intend to submit periodic comprehensive SIP revisions closer to the 1999 RHR's July 31, 2018 deadline, so for those states substantially more than 3.5 years will have elapsed before the progress report becomes due.

3. Final Rule

The EPA is finalizing these provisions regarding scheduling of progress reports, and the aforementioned additional requirement that periodic comprehensive SIP revisions include gap-filling visibility trend information, with no change from proposal.

N. Changes to the Requirement that Regional Haze Progress Reports be SIP Revisions

1. Summary of Proposal

We proposed to revise 40 CFR 51.308(g) regarding the requirements for the form of progress reports, which under the 1999 RHR were required to take the form of SIP revisions that comply with certain procedural requirements.[135] As explained in the proposed rule and elsewhere in this document, the EPA originally included the requirement for progress reports in the 1999 RHR primarily to ensure that the states remain on track between periodic comprehensive SIP revisions. In the 1999 RHR, we required progress reports to be in the form of SIP revisions that meet the procedural requirements of 40 CFR 51.102 and 51.103 (which in turn refer to the requirements of Appendix V of 40 CFR Part 51). Given the requirements for what a state should include in its progress report, we anticipated that these submittals would typically contain narrative descriptions of such things as current visibility conditions and emissions inventories. We did not anticipate that progress reports would typically include new or revised emission limits.[136] Although the EPA specifically intended for progress reports to involve significantly less effort than a periodic comprehensive SIP revision, a state must provide public notice and an opportunity for a public hearing for SIP revisions. In addition, they must conform to certain administrative procedural requirements, provide various administrative material, and must be submitted by an official who is authorized by state law to submit a SIP revision.

We proposed to revise our regulations so that progress reports need not be in the form of SIP revisions, but to require states to consult with FLMs and obtain public comment on their progress reports before submission to the EPA. We also proposed that the SIP revision due in 2021 must include a commitment to prepare and submit these progress reports to the EPA

---

[135] These procedural requirements are detailed in 40 CFR 51.102, 40 CFR 51.103 and Appendix V to Part 51 – Criteria for Determining the Completeness of Plan Submissions.

[136] Under our regulations, if a state were to determine at the time of submitting its progress report that its SIP is or may be inadequate to ensure reasonable progress due to emissions from sources within the state, the state has 1 year in which to submit a SIP revision addressing the inadequacy of its plan. 40 CFR 51.308(h)(4). This SIP revision would contain any required new or revised emission limits.

according to the revised schedule being finalized in this rule (*see* previous section). While these progress reports would be acknowledged and assessed by the EPA, our review of these reports would not result in a formal approval or disapproval of them. In addition, relieving states of the obligation to follow the procedural requirements of 40 CFR 51.102 and 51.103 would free up state resources for other important environmental planning, given the fact that they are resource-intensive. Other advantages to the proposed approach were discussed in detail at proposal.

2. Comments and Responses

Many commenters expressed support, with some suggesting that EPA do away with progress reports entirely (similar sentiments were expressed in comments on progress report timing; see previously in this document). Other commenters opposed eliminating the requirement that progress reports take the form of SIP revisions, and expressed that review by EPA should at least involve a finding of adequacy or inadequacy.

In response to comments opposing eliminating the requirement that progress reports be SIP revisions, the EPA would like to reiterate that as part of our review of a progress report, we will follow up with the state on any appropriate next steps, and we note again that there are additional remedies (such as undertaking a less formal assessment of the results of the implementation of the previously submitted SIP) available to the EPA in the event a state fails to properly submit a progress report.

Some comments expressed concern that the EPA would use progress reports as a basis for a "SIP call" and opined that progress reports should only provide information for subsequent SIP submittals. It should be noted, however, that 40 CFR 51.308(h), which we are not revising in any material way, already requires that if a state has determined in its progress report that its implementation plan is or may be inadequate to ensure reasonable progress due to emissions within that state, it must revise its current SIP to address its deficiencies. Thus, there is already a mechanism under which states must use the information in their progress reports to assess the adequacy of their existing SIPs. Additionally, under CAA section 110(k)(5), the EPA has the authority to review a SIP and assess the adequacy of that SIP. While this authority is discretionary, when and if the EPA does make a determination about the adequacy of a regional haze SIP it must do so reasonably, and this may require consideration of the information in a progress report. Therefore, we are not including in the final rule any provision saying that the content of a progress report may not be used as part of the basis for a SIP call action.

We will further consider a suggestion from one commenter that we provide a centralized website that would inform the public of which progress reports are currently available for public comment at the state level and the planned end of each comment period.

3. Final Rule

The EPA is finalizing the proposal to eliminate the requirement that progress reports take the form of SIP revisions. The EPA would like to emphasize (as explained at proposal) that although progress reports will no longer be required to take the form of SIP revisions, states will still be required to include the required progress report elements listed in 40 CFR 51.308(g)(1) through 40 CFR 51.308(g)(8), in particular the assessment of whether the existing SIP elements are sufficient to enable a state to meet all established RPGs for the period covered by the most recent periodic SIP revision. We are also retaining the requirement that states consult with FLMs and obtain public comment on their progress reports before submission to the EPA.[137] Also, 40 CFR 51.308(h) will continue to require that at the same time the state is required to submit a

[137] We discuss the timing for consultation elsewhere in this preamble.

progress report, it must also take one of four listed actions concerning whether the SIP is adequate to achieve established goals for visibility improvement, and the state will continue to have an obligation to revise its SIP to address any plan deficiencies within 1 year of submission of a determination that the SIP is or may be inadequate.

O. Changes to Requirements Related to the Grand Canyon Visibility Transport Commission

1. Summary of Proposal

As noted in the proposal, 40 CFR 51.309 has limited applicability going forward because its provisions apply only to 16 Class I areas covered by the Grand Canyon Visibility Transport Commission Report, only to three states that chose to rely on the special provisions in this section and only to SIPs for the first regional haze implementation period (i.e., through 2018). However, we proposed certain conforming revisions to avoid confusion going forward, including the following:

- Revising 40 CFR 51.309(d)(4)(v) to correctly refer to the new 40 CFR 51.302(b) (in lieu of (e), which no longer exists in the proposed 40 CFR 51.302) and to delete the reference to BART since it does not appear in 40 CFR 51.302(b).
- Changing the title of 40 CFR 51.309(c)(10), Periodic implementation plan revisions, to include "and progress reports" at the end, to complement the revisions that will no longer require progress reports be considered SIP revisions.
- Revising 40 CFR 51.309(c)(10) to preserve the 1999 RHR's requirement that the progress reports due in 2013 take the form of SIP revisions, but direct the reader to the provisions of 40 CFR 51.308(g) for subsequent progress reports.

- Revising 40 CFR 51.309(c)(10)(iv) to indicate that subsequent progress reports are subject to the requirements of 40 CFR 51.308(h) regarding determinations of adequacy of existing SIPs.
- Revising 40 CFR 51.309(g)(2)(iii) to correct a typographical error.

2. Comments and Responses

Few comments were received on the proposed revisions to 40 CFR 51.309. Of those, most concerned fire issues, and this subject matter is treated elsewhere in this document. One commenter requested clarification on what happens to states participating in the GCVTC after 2018, and in response the EPA would like to clarify that all measures and obligations contained in a SIP approved pursuant to 40 CFR 51.309 must continue to be implemented unless the SIP itself provides for that measure or obligation to sunset, that the revised provisions of 40 CFR 51.309 will apply to any SIP revision that would revise a SIP provision that was part of the basis of EPA initially approving the SIP as meeting the requirements of the 1999 RHR's 40 CFR 51.309 and that future periodic comprehensive SIP revisions and progress reports from these states will be subject to the requirements of 40 CFR 51.308(f) and (g), respectively.

3. Final Rule

All revisions to 40 CFR 51.309 are being finalized without change from proposal.

V. Environmental Justice Considerations

The EPA believes this action will not have disproportionately high and adverse human health, well-being or environmental effects on minority, low-income or indigenous populations because it will not negatively affect the level of protection provided to human health, well-being or the environment under the CAA's visibility protection program. These revisions to the RHR alter procedural and timing aspects of the SIP requirements for visibility protection but do not substantively change the requirement that SIPs provide for reasonable progress towards the goal of natural visibility conditions. These SIP requirements are designed to protect all segments of the general population.

The EPA acknowledges that the delay in submitting SIP revisions from 2018 to 2021 might, but will not necessarily, affect the schedule on which sources must comply with any new requirements. One commenter said that any such delay in reducing emissions is likely to disproportionately impact children, communities of color and the economically disadvantaged. However, because neither the CAA nor the 1999 RHR set specific deadlines for when sources must comply with any new requirements in a state's next periodic comprehensive SIP revision, states have substantial discretion in establishing reasonable compliance deadlines for measures in their SIPs. Given this, we expect to see a range of compliance deadlines in the next round of regional haze SIPs from early in the second implementation period to 2028, depending on the types of measures adopted, and this would have occurred regardless of whether these changes had been finalized. Thus, the EPA believes the delay in the periodic comprehensive SIP revision submission deadline from 2018 to 2021 will not meaningfully reduce the overall progress towards better visibility made by the end of 2028 and will not meaningfully adversely affect environmental protection for any segments of the population. Furthermore, by reducing uncertainty about the requirements of the RHR and in some regards making those requirements more protective, we believe this action is likely to improve public health protection.

VI. Statutory and Executive Order Reviews

A. *Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review*

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this final rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned the EPA ICR number 2540.02. A copy of the ICR supporting statement is available in the docket for this rule, and it is briefly summarized here.

The EPA is finalizing revisions to requirements for state regional haze planning to change the requirements that must be met by states in developing regional haze SIPs, periodic comprehensive SIP revisions, and progress reports for regional haze. The main intended effects of this rulemaking are to provide states with additional time to submit regional haze plans for the second implementation period and to provide states with an improved schedule and process for progress report submission. Further reductions in burden on states for the second planning period include removal of the requirement for progress reports to be SIP revisions, clarifying that states are not required to project emissions inventories as part of preparing a progress report, and relieving the state of the need to review its visibility monitoring strategy within the context of the progress report. With all of these changes considered, the overall burden on states would represent a reduction compared to what would otherwise occur if the provisions of the 1999 RHR were to stay in place. However, we agree with public comments received on the ICR for the proposed rule indicating that the EPA's previous estimates of burden for the 1999 RHR, as well as estimates of burden for the proposed rule, did not accurately reflect the level of effort required to draft SIPs and progress reports. Although at proposal, the total estimated burden for the applicable period of this ICR (i.e., 2016-2019) was estimated to be reduced from 10,307 hours (per year) to 5,974 hours (per year), and total estimated cost was expected to be reduced from $510,498 (per year) to $295,876 (per year), taking into account the information submitted by the commenters, the EPA now estimates burden under the final rule for the applicable period of 2016-2019 to be 13,310 hours (per year) and total estimated cost to be $659,245 (per year). Please note that the EPA believes the final rule will allow for a reduction in effort compared to the 1999 RHR. Thus, if the SIP development and other were undertaken under the 1999 RHR, the costs would be higher than with this final rule. The apparent increase in estimated hours and cost is related to updates of prior estimates in light of more accurate information. Despite this, the EPA projects that the total estimated burden and cost associated with the final rule are less than would be required if the rule revisions were not made. The revisions, for example, extend planning deadlines, reduce the number of SIP submissions to the EPA, relieve states of the need to supply progress reports in the form of formal SIP revisions, and relieve the state of the need to review its visibility monitoring strategy within the context of the progress report. In addition, in accordance with OMB guidance, these numbers reflect the average burden on states per year over the next 3 years only. This burden will vary from year to year, and due to the nature of an average, some states may be above the average while other states may be below the average. The "per-year" numbers provided here are the 3-year averages, and these 3-year averages will also vary. For example, the prior 3-year period (associated with the prior ICR) was not an active SIP development period, and therefore burden on states was relatively low in comparison to the 3-year period associated with this ICR. During this 3-year period states will be taking steps to prepare their next SIPs. SIP development and adoption will continue into the following 3-year period (approximately 2019-2022), and then subside until the next SIP is due in 2028, resulting in a reduced burden compared to the estimates reflected here. For more information and a summary and response to comments received on the proposed rule ICR, please see the Information Collection Request Supporting Statement for EPA ICR Number 2540.02. ICR for Final Revisions to the Regional Haze Regulations, in the docket for this rule. All states are required to submit regional haze SIPs and progress reports under this rule.

Respondents/affected entities: All state air agencies.

Respondent's obligation to respond: Mandatory, in accordance with the provisions of the 1999 RHR.

Estimated number of respondents: 52: 50 states, District of Columbia and U.S. Virgin Islands.

Frequency of response: Approximately every 10 years (SIP) and approximately every 10 years (progress report).

Total estimated burden: 13,310 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $659,245 (per year), includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Entities potentially affected directly by these rule revisions include state governments, and for the purposes of the RFA, state governments are not considered small governments.

Tribes may choose to follow the provisions of the RHR but are not required to do so. Other types of small entities are not directly subject to the requirements of this rule.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531-1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It does not have a substantial direct effect on one or more Indian tribes. Furthermore, these regulation revisions do not affect the relationship or distribution of power and responsibilities between the federal government and Indian tribes. The CAA and the TAR establish the relationship of the federal government and tribes in characterizing air quality and developing plans to protect visibility in Class I areas, and these revisions to the regulations do nothing to modify that relationship. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, the EPA held public hearings attended by members of tribes and separate meetings with tribal representatives to discuss the revisions proposed in this action. The EPA also provided an opportunity for all interested parties to provide oral or written comments on potential concepts for the EPA to address during the rule revision process. Summaries of these meetings are included in the docket for this rule. The EPA also offered to consult with any tribal government to discuss this proposal. A copy of this offer for consultation can be found in the docket for this rulemaking. No tribes requested consultation. One tribal organization submitted comments, which generally endorsed the proposed revisions. However, this commenter said that this action does have implications to tribes and that the EPA must develop an accountability process to ensure meaningful and timely input to states as they implement the revised requirements of the RHR. We acknowledge this comment but we do not find it to contain a basis for changing our finding that Executive Order 13175 does not apply to this action. *See* also Section III.B.5 of this document for further discussion regarding the role of tribes in visibility protection.

G. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action may not have disproportionately high and adverse effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898.[138] The results of our evaluation are contained in Section V of this document.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the U.S. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

VII. Statutory Authority

The statutory authority for this action is provided by 42 U.S.C. 7403, 7407, 7410 and 7601.

---

[138] 59 FR 7629 (February 16, 1994).

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Nitrogen dioxide, Particulate matter, Sulfur oxides, Transportation, Volatile organic compounds.

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Nitrogen dioxide, Particulate matter, Sulfur oxides, Transportation, Volatile organic compounds.

Dated:

Gina McCarthy,
Administrator.

For the reasons stated in the preamble, part 51 and part 52 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401-7671q.

Subpart P—Protection of Visibility

2. Section 51.300 is amended by revising paragraph (b) to read as follows:

§ 51.300 Purpose and applicability.

* * * * *

(b) *Applicability* The provisions of this subpart are applicable to all States as defined in section 302(d) of the Clean Air Act (CAA) except Guam, Puerto Rico, American Samoa, and the Northern Mariana Islands.

* * * * *

3. Section 51.301 is amended by:
    a. Adding the definitions in alphabetical order for “Baseline visibility condition,” “Clearest days,” and “Current visibility condition;”
    b. Revising the definition of “Deciview;”
    c. Adding the definitions in alphabetical order for “Deciview index” and “End of the applicable implementation period;”

d. Revising the definition of “Least impaired days,” “Mandatory Class I Federal Area,” “Most impaired days,” and “Natural conditions;”

e. Adding the definitions in alphabetical order for “Natural visibility,” “Natural visibility condition,” and “Prescribed fire;”

f. Revising the definitions of “Reasonably attributable” and “Regional haze;”

g. Adding the definition in alphabetical order for “Visibility;”

h. Removing the definition of “Visibility impairment”

i. Adding the definition of “Visibility impairment or anthropogenic visibility impairment:” and,

j. Adding the definitions in alphabetical order for “Wildfire,” and “Wildland.”

The revisions and additions read as follows:

§ 51.301 Definitions.

* * * * *

Baseline visibility condition means the average of the five annual averages of the individual values of daily visibility for the period 2000-2004 unique to each Class I area for either the most impaired days or the clearest days.

* * * * *

Clearest days means the twenty percent of monitored days in a calendar year with the lowest values of the deciview index.

Current visibility condition means the average of the five annual averages of individual values of daily visibility for the most recent period for which data are available unique to each Class I area for either the most impaired days or the clearest days.

Deciview is the unit of measurement on the deciview index scale for quantifying in a standard manner human perceptions of visibility.

* * * * *

Deciview index means a value for a day that is derived from calculated or measured light extinction, such that uniform increments of the index correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to very obscured. The deciview index is calculated based on the following equation (for the purposes of calculating deciview using IMPROVE data, the atmospheric light extinction coefficient must be calculated from aerosol measurements and an estimate of Rayleigh scattering):

Deciview index=10 ln (b_{ext}/10 Mm^{-1}).

b_{ext}=the atmospheric light extinction coefficient, expressed in inverse megameters (Mm−1).

End of the applicable implementation period means December 31 of the year in which the next periodic comprehensive implementation plan revision is due under §51.308(f).

* * * * *

Least impaired days means the twenty percent of monitored days in a calendar year with the lowest amounts of visibility impairment.

* * * * *

Mandatory Class I Federal Area or *Mandatory Federal Class I Area* means any area identified in part 81, subpart D of this title.

Most impaired days means the twenty percent of monitored days in a calendar year with the highest amounts of anthropogenic visibility impairment.

Natural conditions reflect naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration, and may refer to the conditions on a single day or a set of days. These phenomena include, but are not limited to, humidity, fire events, dust storms, volcanic activity, and biogenic emissions from soils and trees. These phenomena may be near or far from a Class I area and may be outside the United States.

Natural visibility means visibility (contrast, coloration, and texture) on a day or days that would have existed under natural conditions. Natural visibility varies with time and location, is estimated or inferred rather than directly measured, and may have long-term trends due to long-term trends in natural conditions.

Natural visibility condition means the average of individual values of daily natural visibility unique to each Class I area for either the most impaired days or the clearest days.

* * * * *

Prescribed fire means any fire intentionally ignited by management actions in accordance with applicable laws, policies, and regulations to meet specific land or resource management objectives.

Reasonably attributable means attributable by visual observation or any other appropriate technique.

* * * * *

Regional haze means visibility impairment that is caused by the emission of air pollutants from numerous anthropogenic sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

* * * * *

Visibility means the degree of perceived clarity when viewing objects at a distance. Visibility includes perceived changes in contrast, coloration, and texture elements in a scene.

Visibility impairment or *anthropogenic visibility impairment* means any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.

* * * * *

Wildfire means any fire started by an unplanned ignition caused by lightning; volcanoes; other acts of nature; unauthorized activity; or accidental, human-caused actions, or a prescribed fire that has developed into a wildfire. A wildfire that predominantly occurs on wildland is a natural event.

Wildland means an area in which human activity and development is essentially non-existent, except for roads, railroads, power lines, and similar transportation facilities. Structures, if any, are widely scattered.

* * * * *

4. Revise § 51.302 to read as follows:

§ 51.302 Reasonably attributable visibility impairment.

(a) The affected Federal Land Manager may certify, at any time, that there exists reasonably attributable visibility impairment in any mandatory Class I Federal area and identify which single source or small number of sources is responsible for such impairment. The affected Federal Land Manager will provide the certification to the State in which the impairment occurs and the State(s) in which the source(s) is located. The affected Federal Land Manager shall provide the State(s) in which the source(s) is located an opportunity to consult on the basis of the planned certification, in person and at least 60 days prior to providing the certification to the State(s).

(b) The State(s) in which the source(s) is located shall revise its regional haze implementation plan, in accordance with the schedule set forth in paragraph (d) of this section, to include for each source or small number of sources that the Federal Land Manager has identified in whole or in part for reasonably attributable visibility impairment as part of a certification under paragraph (a) of this section:

(1) A determination, based on the factors set forth in §51.308(f)(2), of the control measures, if any, that are necessary with respect to the source or sources in order for the plan to make reasonable progress toward natural visibility conditions in the affected Class I Federal area;

(2) Emission limitations that reflect the degree of emission reduction achievable by such control measures and schedules for compliance as expeditiously as practicable; and

(3) Monitoring, recordkeeping, and reporting requirements sufficient to ensure the enforceability of the emission limitations.

(c) If a source that the Federal Land Manager has identified as responsible in whole or in part for reasonably attributable visibility impairment as part of a certification under paragraph (a) of this section is a BART-eligible source, and if there is not in effect as of the date of the certification a fully or conditionally approved implementation plan addressing the BART requirement for that source (which existing plan may incorporate either source-specific emission limitations reflecting the emission control performance of BART, an alternative program to address the BART requirement under §51.308(e)(2), (3), and (4), or for sources of SO_2, a program approved under paragraph §51.309(d)(4)), then the State shall revise its regional haze implementation plan to meet the requirements of §51.308(e) with respect to that source, taking into account current conditions related to the factors listed in §51.308(e)(1)(ii)(A). This requirement is in addition to the requirement of paragraph (b) of this section.

(d) For any existing reasonably attributable visibility impairment the Federal Land Manager certifies to the State(s) under paragraph (a) of this section, the State(s) shall submit a revision to its regional haze implementation plan that includes the elements described in paragraphs (b) and (c) no later than 3 years after the date of the certification. The State(s) is not required at that time to also revise its reasonable progress goals to reflect any additional emission reductions required from the source or sources. In no case shall such a revision in response to a reasonably attributable visibility impairment certification be due before July 31, 2021.

5. Section 51.303 is amended by revising paragraph (a)(1) to read as follows:

§ 51.303 Exemptions from control.

(a)(1) Any existing stationary facility subject to the requirement under §51.302(c) or §51.308(e) to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement.

* * * * *

6. Revise § 51.304 ti read as follows:

§ 51.304 Identification of integral vistas.

(a) Federal Land Managers were required to identify any integral vistas on or before December 31, 1985, according to criteria the Federal Land Managers developed. These criteria must have included, but were not limited to, whether the integral vista was important to the visitor's visual experience of the mandatory Class I Federal area.

(b) The following integral vistas were identified by Federal Land Managers: at Roosevelt Campobello International Park, from the observation point of Roosevelt cottage and beach area, the viewing angle from 244 to 256 degrees; and at Roosevelt Campobello International Park, from the observation point of Friar's Head, the viewing angle from 154 to 194 degrees.

(c) The State must list in its implementation plan any integral vista listed in paragraph (b) of this section.

7. Revise § 51.305 to rea as follows:

§ 51.305 Monitoring for reasonably attributable visibility impairment.

For the purposes of addressing reasonably attributable visibility impairment, if the Administrator, Regional Administrator, or the affected Federal Land Manager has advised a State containing a mandatory Class I Federal area of a need for monitoring to assess reasonably attributable visibility impairment at the mandatory Class I Federal area in addition to the monitoring currently being conducted to meet the requirements of §51.308(d)(4), the State must include in the next implementation plan revision to meet the requirement of §51.308(f) an appropriate strategy for evaluating reasonably attributable visibility impairment in the mandatory Class I Federal area by visual observation or other appropriate monitoring techniques. Such strategy must take into account current and anticipated visibility monitoring research, the availability of appropriate monitoring techniques, and such guidance as is provided by the Agency.

§ 51.306 [Removed and Reserved]

8. Section 51.306 is removed and reserved.

9. Section 51.307 is amended by revising paragraphs (a) introductory text, (b)(1) and (2) to read as follows:

§ 51.307 New source review.

(a) For purposes of new source review of any new major stationary source or major modification that would be constructed in an area that is designated attainment or unclassified under section 107(d) of the CAA, the State plan must, in any review under §51.166 with respect to visibility protection and analyses, provide for:

* * * * *

(b) * * *

(1) That may have an impact on any integral vista of a mandatory Class I Federal area listed in §51.304(b), or

(2) That proposes to locate in an area classified as nonattainment under section 107(d)(1) of the Clean Air Act that may have an impact on visibility in any mandatory Class I Federal area.

* * * * *

10. Section 51.308 is amended by:

a. Revising paragraph (b);

b. Revising paragraphs (d)(2)(iv), (d)(3) introductory text, (e)(2)(v), (e)(4) and (5), (f), (g) introductory text, and (g)(3) through (7);

c. Adding paragraph (g)(8); and

d. Revising paragraphs (h) introductory text, (h)(1), (i)(2) introductory text, (i)(2)(ii), and (i)(3) and (4).

The revisions and additions read as follows:

§ 51.308 Regional haze program requirements.

* * * * *

(b) *When are the first implementation plans due under the regional haze program?* Except as provided in §51.309(c), each State identified in §51.300(b) must submit, for the entire State, an implementation plan for regional haze meeting the requirements of paragraphs (d) and (e) of this section no later than December 17, 2007.

* * * * *

(d) * * *

(2) * * *

(iv) For the first implementation plan addressing the requirements of paragraphs (d) and (e) of this section, the number of deciviews by which baseline conditions exceed natural visibility conditions for the most impaired and least impaired days.

(3) *Long-term strategy for regional haze.* Each State listed in §51.300(b) must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas. In establishing its long-term strategy for regional haze, the State must meet the following requirements:

* * * * *

(e) * * *

(2) * * *

(v) At the State's option, a provision that the emissions trading program or other alternative measure may include a geographic enhancement to the program to address the requirement under §51.302(b) or (c) related to reasonably attributable impairment from the pollutants covered under the emissions trading program or other alternative measure.

* * * * *

(4) A State whose sources are subject to a trading program established under part 97 of this chapter in accordance with a federal implementation plan set forth in §52.38 or §52.39 of this

chapter or a trading program established under a SIP revision approved by the Administrator as meeting the requirements of §52.38 or §52.39 of this chapter need not require BART-eligible fossil fuel-fired steam electric plants in the State to install, operate, and maintain BART for the pollutant covered by such trading program in the State. A State may adopt provisions, consistent with the requirements applicable to the State's sources for such trading program, for a geographic enhancement to the trading program to address any requirement under §51.302(b) or (c) related to reasonably attributable impairment from the pollutant covered by such trading program in that State.

(5) After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraphs (d) and (f) of this section, as applicable, in the same manner as other sources.

* * * * *

(f) *Requirements for periodic comprehensive revisions of implementation plans for regional haze.* Each State identified in §51.300(b) must revise and submit its regional haze implementation plan revision to EPA by July 31, 2021, July 31, 2028, and every 10 years thereafter. The plan revision due on or before July 31, 2021, must include a commitment by the State to meet the requirements of paragraph (g) of this section. In each plan revision, the State must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State. To meet the core requirements for regional haze for these areas, the State must submit an implementation plan containing the following plan elements and supporting documentation for all required analyses:

(1) *Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress.* For each mandatory Class I Federal area located within the State, the State must determine the following:

(i) *Baseline visibility conditions for the most impaired and clearest days.* The period for establishing baseline visibility conditions is 2000 to 2004. The State must calculate the baseline visibility conditions for the most impaired days and the clearest days using available monitoring data. To determine the baseline visibility condition, the State must calculate the average of the annual deciview index values for the most impaired days and for the clearest days for the calendar years from 2000 to 2004. The baseline visibility condition for the most impaired days or the clearest days is the average of the respective annual values. For purposes of calculating the uniform rate of progress, the baseline visibility condition for the most impaired days must be associated with the last day of 2004. For mandatory Class I Federal areas without onsite monitoring data for 2000-2004, the State must establish baseline values using the most representative available monitoring data for 2000-2004, in consultation with the Administrator or his or her designee. For mandatory Class I Federal areas with incomplete monitoring data for 2000-2004, the State must establish baseline values using the 5 complete years of monitoring data closest in time to 2000-2004.

(ii) *Natural visibility conditions for the most impaired and clearest days*. A State must calculate natural visibility condition by estimating the average deciview index existing under natural conditions for the most impaired days or the clearest days based on available monitoring information and appropriate data analysis techniques; and

(iii) *Current visibility conditions for the most impaired and clearest days*. The period for calculating current visibility conditions is the most recent 5-year period for which data are available. The State must calculate the current visibility conditions for the most impaired days and the clearest days using available monitoring data. To calculate each current visibility condition, the State must calculate the average of the annual deciview index values for the years in the most recent 5-year period. The current visibility condition for the most impaired or the clearest days is the average of the respective annual values.

(iv) *Progress to date for the most impaired and clearest days*. Actual progress made towards the natural visibility condition since the baseline period, and actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions, for the most impaired and for the clearest days.

(v) *Differences between current visibility condition and natural visibility condition*. The number of deciviews by which the current visibility condition exceeds the natural visibility condition, for the most impaired and for the clearest days.

(vi) *Uniform rate of progress*. (A) The uniform rate of progress for each mandatory Class I Federal area in the State. To calculate the uniform rate of progress, the State must compare the baseline visibility condition for the most impaired days to the natural visibility condition for the most impaired days in the mandatory Class I Federal area and determine the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period in order to attain natural visibility conditions by the end of 2064.

(B) As part of its implementation plan submission, the State may propose (1) an adjustment to the uniform rate of progress for a mandatory Class I Federal area to account for impacts from anthropogenic sources outside the United States and/or (2) an adjustment to the uniform rate of progress for the mandatory Class I Federal area to account for impacts from wildland prescribed fires that were conducted with the objective to establish, restore, and/or maintain sustainable and resilient wildland ecosystems, to reduce the risk of catastrophic wildfires, and/or to preserve endangered or threatened species during which appropriate basic smoke management practices were applied. To calculate the proposed adjustment(s), the State must add the estimated impact(s) to the natural visibility condition and compare the baseline visibility condition for the most impaired days to the resulting sum. If the Administrator determines that the State has estimated the impact(s) from anthropogenic sources outside the United States and/or wildland prescribed fires using scientifically valid data and methods, the Administrator may approve the proposed adjustment(s) to the uniform rate of progress.

(2) *Long-term strategy for regional haze.* Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). In establishing its long-term strategy for regional haze, the State must meet the following requirements:

(i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.

(ii) The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

(A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.

(B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.

(C) In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory Class I Federal area, the State must describe the actions taken to resolve the disagreement. In reviewing the State's implementation plan, the Administrator will take this information into account in determining whether the plan provides for reasonable progress at each mandatory Class I Federal area that is located in the State or that may be affected by emissions from the State. All substantive interstate consultations must be documented.

(iii) The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects. The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants. The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part. However, if a State has made a submission for a new inventory year to meet the requirements of subpart A in the period 12 months prior to submission of the SIP, the State may use the inventory year of its prior submission.

(iv) The State must consider the following additional factors in developing its long-term strategy:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;

(B) Measures to mitigate the impacts of construction activities;

(C) Source retirement and replacement schedules;

(D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and

(E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

(3) *Reasonable progress goals.* (i) A state in which a mandatory Class I Federal area is located must establish reasonable progress goals (expressed in deciviews) that reflect the visibility conditions that are projected to be achieved by the end of the applicable implementation period as a result of those enforceable emissions limitations, compliance schedules, and other measures required under paragraph (f)(2) that can be fully implemented by the end of the applicable implementation period, as well as the implementation of other requirements of the CAA. The long-term strategy and the reasonable progress goals must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.

(ii)(A) If a State in which a mandatory Class I Federal area is located establishes a reasonable progress goal for the most impaired days that provides for a slower rate of improvement in visibility than the uniform rate of progress calculated under paragraph (f)(1)(vi) of this section, the State must demonstrate, based on the analysis required by paragraph (f)(2)(i) of this section, that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy. The State must provide to the public for review as part of its implementation plan an assessment of the number of years it would take to attain natural visibility conditions if visibility improvement were to continue at the rate of progress selected by the State as reasonable for the implementation period.

(B) If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

(iii) The reasonable progress goals established by the State are not directly enforceable but will be considered by the Administrator in evaluating the adequacy of the measures in the implementation plan in providing for reasonable progress towards achieving natural visibility conditions at that area.

(iv) In determining whether the State's goal for visibility improvement provides for reasonable progress towards natural visibility conditions, the Administrator will also evaluate the demonstrations developed by the State pursuant to paragraphs (f)(2) and (f)(3)(ii)(A) of this section and the demonstrations provided by other States pursuant to paragraphs (f)(2) and (f)(3)(ii)(B) of this section.

(4) If the Administrator, Regional Administrator, or the affected Federal Land Manager has advised a State of a need for additional monitoring to assess reasonably attributable visibility impairment at the mandatory Class I Federal area in addition to the monitoring currently being conducted, the State must include in the plan revision an appropriate strategy for evaluating reasonably attributable visibility impairment in the mandatory Class I Federal area by visual observation or other appropriate monitoring techniques.

(5) So that the plan revision will serve also as a progress report, the State must address in the plan revision the requirements of paragraphs (g)(1), (g)(2), (g)(4), and (g)(5) of this section. However, the period to be addressed for these elements shall be the period since the most recent progress report.

(6) *Monitoring strategy and other implementation plan requirements*. The State must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the State. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments network. The implementation plan must also provide for the following:

(i) The establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals to address regional haze for all mandatory Class I Federal areas within the State are being achieved.

(ii) Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the State.

(iii) For a State with no mandatory Class I Federal areas, procedures by which monitoring data and other information are used in determining the contribution of emissions from within the State to regional haze visibility impairment at mandatory Class I Federal areas in other States.

(iv) The implementation plan must provide for the reporting of all visibility monitoring data to the Administrator at least annually for each mandatory Class I Federal area in the State. To the extent possible, the State should report visibility monitoring data electronically.

(v) A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically.

(vi) Other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility.

(g) *Requirements for periodic reports describing progress towards the reasonable progress goals.* Each State identified in §51.300(b) must periodically submit a report to the Administrator evaluating progress towards the reasonable progress goal for each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State. The first progress report is due 5 years from submittal of the initial implementation plan addressing paragraphs (d) and (e) of this section. The first progress reports must be in the form of implementation plan revisions that comply with the procedural requirements of §51.102 and §51.103. Subsequent progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter. Subsequent progress reports must be made available for public inspection and comment for at least 30 days prior to submission to EPA and all comments received from the public must be submitted to EPA along with the subsequent progress report, along with an explanation of any changes to the progress report made in response to these comments. Periodic progress reports must contain at a minimum the following elements:

* * * * *

(3) For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.

(i)(A) Progress reports due before January 31, 2025. The current visibility conditions for the most impaired and least impaired days.

(B) Progress reports due on and after January 31, 2025. The current visibility conditions for the most impaired and clearest days;

(ii)(A) Progress reports due before January 31, 2025. The difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions.

(B) Progress reports due on and after January 31, 2025. The difference between current visibility conditions for the most impaired and clearest days and baseline visibility conditions.

(iii)(A) Progress reports due before January 31, 2025. The change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under paragraph (f) of this section.

(B) Progress reports due on and after January 31, 2025. The change in visibility impairment for the most impaired and clearest days over the period since the period addressed in the most recent plan required under paragraph (f) of this section.

(4) An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.

(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.

(6) An assessment of whether the current implementation plan elements and strategies are sufficient to enable the State, or other States with mandatory Class I Federal areas affected by emissions from the State, to meet all established reasonable progress goals for the period covered by the most recent plan required under paragraph (f) of this section.

(7) For progress reports for the first implementation period only, a review of the State's visibility monitoring strategy and any modifications to the strategy as necessary.

(8) For a state with a long-term strategy that includes a smoke management program for prescribed fires on wildland that conducts a periodic program assessment, a summary of the most recent periodic assessment of the smoke management program including conclusions if any that were reached in the assessment as to whether the program is meeting its goals regarding improving ecosystem health and reducing the damaging effects of catastrophic wildfires.

(h) *Determination of the adequacy of existing implementation plan.* At the same time the State is required to submit any progress report to EPA in accordance with paragraph (g) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

(1) If the State determines that the existing implementation plan requires no further substantive revision at this time in order to achieve established goals for visibility improvement and

emissions reductions, the State must provide to the Administrator a declaration that revision of the existing implementation plan is not needed at this time.

* * * * *

(i) * * *

(2) The State must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy. The opportunity for consultation will be deemed to have been early enough if the consultation has taken place at least 120 days prior to holding any public hearing or other public comment opportunity on an implementation plan (or plan revision) for regional haze required by this subpart. The opportunity for consultation on an implementation plan (or plan revision) or on a progress report must be provided no less than 60 days prior to said public hearing or public comment opportunity. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:

* * * * *

(ii) Recommendations on the development and implementation of strategies to address visibility impairment.

(3) In developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers.

(4) The plan (or plan revision) must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.

11. Section 51.309 is amended by:

a. Revising paragraph (b)(4);
b. Removing and reserving paragraph (b)(8);
c. Revising paragraphs (d)(4)(v), (d)(10) introductory text, (d)(10)(i) introductory text, and (d)(10)(ii) introductory text;
d. Adding paragraphs (d)(10)(iii) and (iv); and
e. Revising paragraph (g)(2)(iii).

The revisions and additions read as follows:

§ 51.309 Requirements related to the Grand Canyon Visibility Transport Commission.

* * * * *

(b) * * *

(4) *Fire* means wildfire, wildland fire, prescribed fire, and agricultural burning conducted and occurring on Federal, State, and private wildlands and farmlands.

* * * * *

(d) * * *

(4) * * *

(v) Market Trading Program. The implementation plan must include requirements for a market trading program to be implemented in the event that a milestone is not achieved. The plan shall require that the market trading program be activated beginning no later than 15 months after the end of the first year in which the milestone is not achieved. The plan shall also require that sources comply, as soon as practicable, with the requirement to hold allowances covering their emissions. Such market trading program must be sufficient to achieve the milestones in paragraph (d)(4)(i) of this section, and must be consistent with the elements for such programs outlined in §51.308(e)(2)(vi). Such a program may include a geographic enhancement to the program to address the requirement under §51.302(b) related to reasonably attributable impairment from the pollutants covered under the program.

* * * * *

(10) *Periodic implementation plan revisions and progress reports*. Each Transport Region State must submit to the Administrator periodic reports in the years 2013 and as specified for subsequent progress reports in §51.308(g). The progress report due in 2013 must be in the form of an implementation plan revision that complies with the procedural requirements of §§51.102 and 51.103.

(i) The report due in 2013 will assess the area for reasonable progress as provided in this section for mandatory Class I Federal area(s) located within the State and for mandatory Class I Federal area(s) located outside the State that may be affected by emissions from within the State. This demonstration may be based on assessments conducted by the States and/or a regional planning body. The progress report due in 2013 must contain at a minimum the following elements:

* * * * *

(ii) At the same time the State is required to submit the 5-year progress report due in 2013 to EPA in accordance with paragraph (d)(10)(i) of this section, the State must also take one of the following actions based upon the information presented in the progress report:

* * * * *

(iii) The requirements of §51.308(g) regarding requirements for periodic reports describing progress towards the reasonable progress goals apply to States submitting plans under this section, with respect to subsequent progress reports due after 2013.

(iv) The requirements of §51.308(h) regarding determinations of the adequacy of existing implementation plans apply to States submitting plans under this section, with respect to subsequent progress reports due after 2013.

* * * * *

(g) * * *

(2) * * *

(iii) The Transport Region State may consider whether any strategies necessary to achieve the reasonable progress goals required by paragraph (g)(2) of this section are incompatible with the strategies implemented under paragraph (d) of this section to the extent the State adequately demonstrates that the incompatibility is related to the costs of the compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, or the remaining useful life of any existing source subject to such requirements.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

12. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 et seq.

§ 52.26 [Removed and Reserved]

13. Section 52.26 is removed and reserved.

§ 52.29 [Removed and Reserved]

14. Section 52.29 is removed and reserved.

§ 52.61 [Amended]

15. Section 52.61 is amended by removing and reserving paragraph (b).

16. Section 52.145 is amended by revising paragraph (b) and removing and reserving paragraph (c) to read as follows:

The revision reads as follows:

§ 52.145 Visibility protection.

* * * * *

(b) Regulations for visibility monitoring and new source review. The provisions of §§ 52.27 and 52.28 are hereby incorporated and made part of the applicable plan for the State of Arizona.

* * * * *

§ 52.281 [Amended]

17. Section 52.281 is amended by removing and reserving paragraphs (b) and (e).

18. Section 52.344 is amended by revising paragraph (b) to read as follows:

§ 52.344 Visibility protection.

* * * * *

(b) The Visibility NSR regulations are approved for industrial source categories regulated by the NSR and PSD regulations which have previously been approved by EPA. However, Colorado's NSR and PSD regulations have been disapproved for certain sources as listed in 40 CFR 52.343(a)(1). The provisions of 40 CFR 52.28 are hereby incorporated and made a part of the applicable plan for the State of Colorado for these sources.

19. Section 52.633 is amended by revising paragraph (b) and removing and reserving paragraph (c) to read as follows.

§ 52.633 Visibility protection.

* * * * *

(b) Regulations for visibility monitoring and new source review. The provisions of §§ 52.27 and 52.28 are hereby incorporated and made part of the applicable plan for the State of Hawaii.

* * * * *

§ 52.690 [Amended]

20. Section 52.690 is amended by removing and reserving paragraphs (b) and (c).

§ 52.1033 [Amended]

21. Section 52.1033 is amended by removing and reserving paragraphs (a) and (c).
22. Section 52.1183 is amended by revising paragraph (b) and removing and reserving paragraphs (a) and (c) to read as follows.

§ 52.1183 Visibility protection.

* * * * *

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of Michigan.

* * * * *

23. Section 52.1236 is amended by revising paragraph (b) removing and reserving paragraph (c) to read as follows:

§ 52.1236 Visibility protection.

* * * * *

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of Minnesota.

* * * * *

§ 52.1339 [Amended]

24. Section 52.1339 is amended by removing and reserving paragraph (b).

§ 52.1387 [Amended]

25. Section 52.1387 is amended by removing and reserving paragraph (b).

26. Section 52.1488 is amended by revising paragraph (b) and removing and reserving paragraph (c) to read as follows.

§ 52.1488 Visibility protection.

* * * * *

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of Nevada except for that portion applicable to the Clark County Department of Air Quality and Environmental Management.

* * * * *

27. Section 52.1531 is amended by revising paragraph (b) and removing and reserving paragraph (c) to read as follows.

§ 52.1531 Visibility protection.

* * * * *

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of New Hampshire.

* * * * *

§ 52.2132 [Amended]

28. Section 52.2132 is amended by removing and reserving paragraphs (b) and (c).
29. Section 52.2179 is amended by revising paragraph (b) and removing and reserving paragraph (c) to read as follows:

§ 52.2179 Visibility protection.

* * * * *

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of South Dakota.

* * * * *

§ 52.2304 [Amended]

30. Section 52.2304 is amended by removing and reserving paragraph (b).
31. Section 52.2383 is amended by revising paragraph (b) to read as follows:

§ 52.2383 Visibility protection.

* * * * *

(b) Regulations for visibility monitoring and new source review. The provisions of § 52.27 are hereby incorporated and made part of the applicable plan for the State of Vermont.

32. Section 52.2452 is amended by revising paragraph (a) and removing and reserving paragraphs (b) and (c) to read as follows:

§ 52.2452 Visibility protection.

(a) Reasonably Attributable Visibility Impairment. The requirements of section 169A of the Clean Air Act are not met because the plan does not include approvable measures for meeting the requirements of 40 CFR 51.305 for protection of visibility in mandatory Class I Federal areas.

* * * * *

33. Section 52.2533 is amended by revising paragraphs (a) and (b) and removing and reserving paragraph (c) to read as follows:

§ 52.2533 Visibility protection.

(a) *Reasonably Attributable Visibility Impairment.* The requirements of section 169A of the Clean Air Act are not met because the plan does not include approvable measures for meeting the requirements of 40 CFR 51.305 and 51.307 for protection of visibility in mandatory Class I Federal areas.

(b) Regulation for visibility monitoring and new source review. The provisions of § 52.28 are hereby incorporated and made a part of the applicable plan for the State of West Virginia.

* * * * *

§ 52.2781 [Amended]

34. Section 52.2781 is amended by removing and reserving paragraphs (b) and (c).

Attachment 2

Comments of the Utility Air Regulatory Group on the U.S. Environmental Protection Agency's Proposed Rule, "Protection of Visibility: Amendments to Requirements for State Plans"

Docket No. EPA-HQ-OAR-2015-0531; 81 Fed. Reg. 26942 (May 4, 2016)

August 10, 2016

On May 4, 2016, the U.S. Environmental Protection Agency ("EPA" or "Agency") published a proposed rule, entitled "Protection of Visibility: Amendments to Requirements for State Plans." 81 Fed. Reg. 26942 (May 4, 2016) ("Proposed Rule"). The Proposed Rule would amend key provisions of EPA's visibility regulations at 40 C.F.R. 51.300 to 51.309. EPA proposes, among other things, to adjust the due date for submittal of state implementation plans ("SIPs") for the second planning period of the Clean Air Act's ("CAA" or "Act") regional haze program. Further, EPA proposes substantive changes to that program's requirements, including requirements applicable to reasonable progress goals ("RPGs") and long-term strategies ("LTSs") and changes to the way in which days are selected for purposes of tracking progress toward natural visibility conditions. EPA also proposes changes applicable to the form and content of the regional haze program's five-year progress reports. In addition, EPA proposes revisions to the reasonably attributable visibility impairment ("RAVI") provisions intended to address what has been called "plume blight." EPA says its intention in proposing these revisions is to "continue steady environmental progress in the regional haze program while streamlining its administrative aspects that do not add to environmental protection." 81 Fed. Reg. at 26951.

The Utility Air Regulatory Group ("UARG")[1] supports some aspects of EPA's proposed rule revisions but opposes others or, in some respects, notes that proposed revisions raise

[1] UARG is an ad hoc, not-for-profit group of electric generating companies and national trade associations. UARG's purpose is to participate on behalf of its members collectively in EPA's

concerns. Of particular concern are proposed regulatory changes that appear to be intended to limit, or that at least could be interpreted as having the effect of limiting, state discretion improperly. During the regional haze program's first planning period, EPA on occasion has acknowledged the centrality of state decision-making authority in this area, even while the Agency often overrode state decisions and disregarded the principle of broad state discretion, based on its differences with states on matters of policy and a purported, but misguided, desire to ensure consistency in outcomes among the states.

Any revisions to the visibility rules must properly reflect the role Congress intended for the states when it enacted sections 169A and 169B of the CAA. That role is described in the opinion of the U.S. Court of Appeals for the D.C. Circuit in *American Corn Growers Association v. EPA*, 291 F.3d 1 (D.C. Cir. 2002) ("*Corn Growers*"). The court explained at the outset of its opinion that "[t]he Haze Rule calls for states to play the lead role in designing and implementing regional haze programs to clear the air in national parks and wilderness areas." *Id.* at 2. Applying that principle, the court struck down elements of EPA's 1999 regional haze rule relating to the Act's best available retrofit technology ("BART") requirement, holding that those provisions were "inconsistent with the Act's provisions giving the states broad authority over BART determinations." *Id.* at 8. The decision relied in particular on legislative history demonstrating that Congress purposely rejected broad EPA authority and determined that "Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources." *Id.* Accordingly, where EPA issues a rule that "attempts to deprive the states of some of th[eir] statutory authority" under the regional haze program, it does so "in contravention of the Act." *Id.*

---

rulemakings and other CAA proceedings that affect the interests of electric generators and in litigation arising from those proceedings.

The *Corn Growers* decision restates and applies in the regional haze context the general legal standard governing review of EPA decisions to disapprove SIPs that was announced by the Supreme Court over 40 years ago:

> The Act gives the Agency *no authority to question the wisdom of a State's choices* of emission limitations if they are part of a plan which satisfies the standards of [CAA] § 110(a)(2), and the Agency *may devise and promulgate* a specific plan of its own *only if a State fails to submit an implementation plan which satisfies those standards*. [CAA] § 110(c). Thus, so long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.

Train v. Natural Res. Def. Council v. EPA, 421 U.S. 60, 79 (1975) (emphases added); *see also, e.g.*, CAA § 107(a)(1) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State . . . ."). *Train* construed section 110(a)(2) of the CAA, which includes section 110(a)(2)(J)'s requirement that SIPs address requirements for visibility protection under sections 169A and 169B in Part C of Title I of the Act. As *Corn Growers* illustrates, states have, if anything, even more latitude with respect to their actions under sections 169A and 169B than they do generally under section 110(a)(2). *See also, e.g.*, *Texas v. EPA*, No. 16-60118 (5th Cir., July 15, 2016), slip op. at 3 (addressing the breadth of state discretion under the regional haze reasonable progress program: "The Clean Air Act gives each state 'wide discretion in formulating its plan' for achieving the air quality standards set by EPA.") (quoting *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976)).

More recent decisions by the federal appellate courts confirm that Congress gave states broad decision-making discretion under the regional haze program and that EPA's authority to disapprove SIPs is narrowly circumscribed. For instance, in *North Dakota v. EPA*, 730 F.3d 750 (8th Cir. 2013), the court explained that under the CAA, the states have primary responsibility for implementing CAA programs and emphasized that EPA has authority to substitute its decisions for those of a state by promulgating a federal implementation plan ("FIP") only when the state fails to submit a SIP, submits an incomplete SIP, or submits a SIP that does not meet the Act's requirements.[2] *Id.* at 757. In other decisions, including even those where EPA was not held to have acted unlawfully when it disapproved SIPs, the courts have recognized that a "higher standard"—*i.e.*, a more demanding standard of review—is applied in judicial scrutiny of EPA disapproval of a regional haze SIP than it is in review of EPA decisions promulgating regional haze FIPs. *See, e.g.*, *Oklahoma v. EPA*, 723 F.3d 1201, 1213 n.7 (10th Cir. 2013). Although the courts have not been uniform in their descriptions of the precise nature of and constraints on EPA's role in reviewing regional haze SIPs, and EPA does have a limited review function that means it will not act automatically to routinely rubber-stamp SIPs without undertaking any substantive review, *see North Dakota*, 730 F.3d at 761 ("EPA is left with more than the ministerial task of *routinely* approving SIP submissions") (emphasis added), it remains the fact that "[t]he Clean Air Act confines EPA's role in implementing air quality standards 'to the ministerial function of reviewing SIPs for consistency with the Act's requirements,'" *Texas*, slip op. at 3 (quoting *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012)).

As a consequence, EPA's revisions to the regional haze rule must conform to the fundamental guiding principle of state primacy in implementation of the visibility program, including state primacy with respect to establishment of RPGs for Class I areas, evaluation of potential reasonable progress emission control requirements for possible inclusion in the state's LTS, interstate consultation, implementation of the RAVI program, and other aspects of

[2] In *North Dakota*, the state conceded that its SIP was based on a significant technical error, and for this reason the reviewing court concluded that the state's determinations in the SIP were not entitled to deference. *See North Dakota*, 730 F.3d at 759-61.

visibility SIPs. In a number of respects, described below, the Proposed Rule—despite proposing some positive reforms of EPA's existing regulations—does not satisfy, or does not appear to satisfy, the principle of state primacy and should be revised or clarified accordingly.

I. EPA Should Take Additional Comments on Its Draft Guidance Document After It Promulgates Final Revisions to the Regional Haze Rule.

The May 4, 2016 notice announcing the public comment period on the Proposed Rule also announced EPA's plan to release "updated guidance on the development of regional haze SIPs . . . separately from this rulemaking." 81 Fed. Reg. at 26945. The Proposed Rule explained that the guidance would address a number of issues that are central to this rulemaking, including consultation between states and the Federal Land Managers ("FLMs"), how to conduct reasonable progress analyses, and important technical issues such as excluding the contributions to visibility impairment that are attributable to emissions from non-U.S. sources and naturally occurring emissions. Without access to and sufficient time to review the draft guidance, the public's ability to comment meaningfully on all aspects of the Proposed Rule would have been seriously constrained. For that reason, UARG asked EPA to extend the original July 5, 2016 deadline for comments on the Proposed Rule "to 90 days after the date on which EPA issues the draft guidance" and to establish a public comment period on the draft guidance that would run coextensively with the public comment period on the Proposed Rule. UARG Letter to the Honorable Gina McCarthy at 2-3 (May 25, 2016), Docket ID No. EPA-HQ-OAR-2015-0531-0108. In response to UARG's and other similar requests, EPA announced an extension of the public comment period on the Proposed Rule from July 5 to August 10, 2016. 81 Fed. Reg. 43180 (July 1, 2016). Shortly after the extension was signed, EPA published a notice of availability of, and a public comment period on, the draft guidance, titled "Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other

Requirements for Regional Haze State Implementation Plans for the Second Implementation Period." 81 Fed. Reg. 44608 (July 8, 2016) ("Draft Guidance"). That notice announced an August 22, 2016 deadline for comments on the Draft Guidance. In light of the need for additional time to consider the complex issues raised by the Draft Guidance and to coordinate comments on the Proposed Rule and the Draft Guidance, on July 20, 2016, UARG submitted to the docket for the Proposed Rule and the docket for the Draft Guidance a letter requesting that EPA extend the deadlines for comments on both documents to September 29, 2016. UARG Letter to the Honorable Gina McCarthy at 2, 4 (July 20, 2016), Docket ID No. EPA-HQ-OAR-2015-0531-0329, EPA-HQ-OAR-2016-0289-0021. UARG requested in the alternative that EPA at least extend the August 10, 2016 deadline for comments on the Proposed Rule to match the deadline (whether August 22, 2016, or a later date) for comments on the Draft Guidance. *Id.* at nn.2, 3. On August 5, 2016, UARG learned that EPA had decided to deny this extension request altogether (although UARG to date has not received a written response to its July 20, 2015 letter).

EPA has not provided a rationale for establishing different comment deadlines in these two proceedings, and the complications presented by commenting on the Proposed Rule in conjunction with the Draft Guidance point to the need for additional coordination of development of the final rule revisions and the guidance document. Indeed, as UARG explained in its comment-period extension request letters, it is impossible to comment on the Proposed Rule in a comprehensive way without a clear understanding of the technical and other matters addressed in the Draft Guidance. The availability of the Draft Guidance during part of the comment period for the Proposed Rule has alleviated some of those problems, although additional time to analyze the highly complex issues addressed in the Draft Guidance would have aided substantially in research for and preparation of comments on the Proposed Rule.

Preparing comments on the Draft Guidance is also complicated by the potential for changes to the Proposed Rule before EPA takes final rulemaking action. Indeed, the Draft Guidance notes that it was drafted as if the Proposed Rule were already final, yet some of the rule revisions apparently assumed to be final in the Draft Guidance appear not to fully or accurately reflect certain elements and nuances of the Proposed Rule. Because of these complications and potential discrepancies, UARG urges EPA to prepare and release a revised version of the Draft Guidance, and to solicit public comments on that revised version, after the Agency has considered and responded to comments on the Proposed Rule and has issued final revisions to the regional haze rule. This approach would allow EPA to solicit and consider comments on a revised draft version of the guidance document that would both reflect EPA's responses to the upcoming comments on the current version of the draft guidance and accurately reflect and take into account the provisions of the final rule revisions.[3]

II. As It Proposes To Do, EPA Should Extend the Deadline for Submittal of Regional Haze SIPs for the Second Implementation Period.

EPA's current regulations require each state to submit a regional haze implementation plan revision to EPA by July 31, 2018, and every 10 years thereafter. 40 C.F.R. § 51.308(f). EPA proposes an extension of the 2018 submittal deadline to July 31, 2021. 81 Fed. Reg. at 26944, 26965.

[3] Because of the close relationship between the Draft Guidance and the Proposed Rule, UARG is submitting the present comments to the EPA docket for the Draft Guidance, Docket No. EPA-HQ-OAR-2016-0289, as well as to the EPA docket for the Proposed Rule, Docket No. EPA-HQ-OAR-2015-0531. UARG's principal comments on the Draft Guidance will be submitted to EPA by the deadline for comments on that document.

As an initial matter, UARG notes that there is no legal impediment to EPA's proposed action. Nothing in section 169A or section 169B of the CAA establishes any specific SIP submittal deadlines for the second planning period or limits EPA's ability to extend such deadlines by rulemaking.

The explanation EPA articulates in the Proposed Rule for this change, moreover, provides a strong and well-reasoned basis for the proposed extension. First, EPA explains that the extension will allow states "to obtain and take into account information on the effects of a number of other regulatory programs that will be affecting sources over the next several years" and that, as a result, states will be able to integrate or coordinate their regional haze SIP revisions with state planning for these other programs. *Id.* at 26944. Thus, the extension "is anticipated to result in greater environmental progress than if planning for these multiple programs were not as well integrated." *Id.* Further, EPA notes that the end date for the second planning period will remain 2028 and that "any control measure included in a SIP submitted by the proposed July 31, 2021, submission deadline will be feasible to implement by 2028." *Id.* at 26944-45 & n.3.

The contents, scope, and voluminous nature of the Draft Guidance provide further compelling support for this extension. As UARG will explain in its upcoming comments on the Draft Guidance, that document contemplates an extremely complex and time-consuming set of actions that states might take in developing SIPs for the second planning period. The Draft Guidance says that it is nonbinding and does not require states to undertake the specific tasks or analyses it describes, although states may choose to do so. On the other hand, some of the actions and analyses recommended by or otherwise described in the Draft Guidance are presented in that document in terms that suggest EPA may later try to treat them as if they were mandatory or at least as if the Draft Guidance creates strong presumptions that states would have an obligation to try to rebut if they do not want to follow them. For instance, the Draft Guidance states or suggests in certain places that if states depart from EPA recommendations, they will have to provide substantial documentation and analytical support for their choices. In this respect, the Proposed Rule in combination with the Draft Guidance appears to go well beyond what the CAA or the current regional haze rules call for with respect to BART SIPs or reasonable progress requirements for the first planning period. Although UARG does not believe EPA can lawfully establish such requirements or presumptions in a guidance document, if states comply with the provisions of the Proposed Rule and follow the recommendations of the Draft Guidance, they undoubtedly will need a very substantial period beyond 2018 to prepare and submit their SIPs for the second planning period.

Because the proposed deadline extension is well supported, will result in more effective environmental policy-making, will not result in any extension of the second planning period or its 2028 milestone date (and therefore will not delay progress toward natural visibility conditions), and in any event is essential in light of other aspects of the proposed rule revisions as well as the Draft Guidance, EPA should promulgate this aspect of the Proposed Rule.

III. EPA's Purported "Clarifications" Regarding the Relationships Among RPGs, the LTS, and State Obligations Are Unfounded and Unreasonable and Are in Fact Substantial Deviations from the Existing Regional Haze Rule.

EPA asserts that it is proposing "clarifications regarding the relationship between reasonable progress goals, long-term strategies and the long-term strategy obligation of all states." *Id.* at 26944. EPA claims these purported clarifications reflect the understanding of "all states" and EPA's own purported "long-held interpretation." *Id.* at 26948-49. One of EPA's purported clarifications is that a state's LTS "is inextricably linked" to its RPGs because those RPGs are, according to EPA, supposed to reflect all emission reduction measures contained in the LTS. *Id.* at 26948. EPA asserts that

> the four reasonable progress factors are considered by a state in setting the reasonable progress goal by virtue of the state having first considered them, and certain other factors listed in § 51.308(d)(3) of the Regional Haze Rule, when deciding what controls are to be included in the long-term strategy. Then, the numerical levels of the reasonable progress goals are the predicted visibility outcome of implementing the long-term strategy in addition to ongoing pollution control programs stemming from other CAA requirements.

Id. at 26948. EPA proposes to codify this interpretation in 40 C.F.R. § 51.308(f)(1)-(3).

This asserted EPA position in fact is *not* stated or reflected in the existing rules or in EPA's 2007 "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program" ("2007 Guidance") and appears to have been newly formulated and stated for the first time in EPA's January 5, 2016 regional haze rule for Texas and Oklahoma. EPA only proposed that rule in December 2014 and published it as a final rule in January 2016, well after the states had prepared and submitted their regional haze SIPs for the first planning period. 79 Fed. Reg. 74818 (Dec. 16, 2014); 81 Fed. Reg. 296 (Jan. 5, 2016). Given the inconsistency of the purported EPA clarification in the Proposed Rule with the 2007 Guidance, and given the very recent pedigree of EPA's articulation of this position in its rule addressing requirements for Texas and Oklahoma, EPA cannot credibly label this a "long-held interpretation."

Likewise, EPA provides no basis for its assertion that "all states" understood EPA's newly minted position on the relationship between RPGs and the LTS. Most states, consistent with the 2007 Guidance, relied on their BART determinations to satisfy all or the bulk of their reasonable progress requirements, leaving little opportunity or reason for states to take any particular position on how their RPGs relate to their LTSs.

It is telling that, despite asserting that "all states" understood EPA's supposedly "long-standing" interpretation, 81 Fed. Reg. at 26944, EPA in the preamble to the Proposed Rule fails to discuss or to cite even once the 2007 Guidance—EPA's governing guidance document to the states on this issue. In fact, EPA's new position that states must develop RPGs *after* they identify emission controls to include in the LTS, and that they necessarily base the RPGs on the projected effects of those controls, contradicts the 2007 Guidance and is inconsistent with the extraordinarily broad scope of state discretion afforded by the CAA's regional haze provisions. The 2007 Guidance addresses the relationship of RPGs to the LTS, and it includes no requirement that a state develop the LTS and determine its emission control measures first and establish RPGs only subsequently based on the controls included in the LTS. In contrast to EPA's novel interpretation, the 2007 Guidance explains that the LTS "is the means through which the State ensures that its RPG will be met." 2007 Guidance at page 1-4; *id.* at page 1-2 ("The RHR [regional haze rule] also requires States to submit *a long-term strategy that includes such measures as are necessary to achieve the RPG* for each Class I area.") (citing 40 C.F.R. § 51.308(d)(3)) (emphasis added); *see also id.* at page 2-3 ("The next step in setting an RPG is to identify and analyze *the measures aimed at achieving the uniform rate of progress* and *to determine whether these measures are reasonable* based on the statutory factors") (emphasis added). In fact, the section of the 2007 Guidance that addresses the process for developing RPGs does not direct a state to develop an LTS before the state sets its RPGs and only thereafter base its RPGs on the visibility improvements the LTS is projected to achieve. On the contrary, the process for establishing RPGs that the 2007 Guidance describes does not even explicitly mention the LTS and in fact describes alternative approaches to RPG development that a state may choose, but is not required, to adopt. *See id.* at 2-1 to 2-4. For instance, a state could, consistent with that guidance and the existing regional haze rule, develop an RPG and *then* evaluate and decide upon appropriate LTS measures *to achieve the RPG*.

EPA's new interpretation is also inconsistent with the text of the existing regional haze rule, as interpreted by the D.C. Circuit. The rule itself provides that "[t]he long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas." 40 C.F.R. § 51.308(d)(3). The D.C. Circuit explained that EPA's 1999 regional haze rule provides that "the determination of what specific control measures must be implemented 'can only be made by a State once it has conducted the necessary technical analyses of emissions, air quality, and the other factors that go into determining reasonable progress.'" *Corn Growers*, 291 F.3d at 4 (quoting 64 Fed. Reg. 35714, 35721 (July 1, 1999)).

In sum, the existing rule does not support EPA's purported clarification in the Proposed Rule. EPA should not mask a significant legal and policy change by incorrectly asserting that it is a long-held and universally understood and accepted interpretation.

In a related provision, EPA proposes new rules to govern the role of interstate consultation in the LTS development process. *See* 81 Fed. Reg. at 26952. The existing regional haze rule requires a state that has emissions that are reasonably anticipated to contribute to visibility impairment in a Class I area in another state to consult with that other state to develop coordinated emission management strategies and to provide that all measures necessary to obtain its share of the emission reductions that are needed have been included in its regional haze SIP. 40 C.F.R. § 51.308(d)(3)(i)-(ii). The rule further requires states to document the technical basis for their emission apportionment determinations and specifically allows states to satisfy this requirement by relying on Regional Planning Organizations' technical analyses. *Id.* § 51.308(d)(3)(iii). Quite properly, these existing provisions reflect states' broad discretion and provide a clear and appropriate safe harbor with respect to states' obligation to document the bases for their determinations.

EPA proposes a new provision, 40 C.F.R. § 51.308(f)(2)(iii), to govern interstate consultation in development of each state's LTS. It is unclear the extent to which EPA believes this proposed revision would effect substantive changes to the way in which interstate consultation is to be conducted. If, however, EPA intends these revisions to codify the position the Agency staked out on interstate consultation in its 2014-2016 regional haze rulemaking for Texas and Oklahoma—which is being challenged in pending litigation in part because of this very issue—then this aspect of the Proposed Rule is unlawful and inconsistent with the CAA's broad delegation of authority to the states.

IV. Some of EPA's Proposed Clarifications Regarding Calculation of the URP Are Appropriate, But the Proposed Additional Demonstration Requirements Are Arbitrary and Not Properly Justified, and EPA Mischaracterizes a Key Element of Its Existing Rules.

EPA proposes revisions to 40 C.F.R. § 51.308(d) to make clear that "in every implementation period, the glidepath or URP line for each Class I area is drawn starting on December 31, 2004, at the value of the 2000–2004 baseline visibility conditions for the 20 percent most impaired days, and ending at the value of natural visibility conditions on December 31, 2064." 81 Fed. Reg. at 26953. UARG believes this clarification is appropriate and helpful to the states. Maintaining a consistent URP and not forcing states to recalculate the glidepath for each implementation period will provide greater certainty to states and regulated sources. Doing so will also, as EPA explains, make clear that "for a Class I area that has achieved more than the URP in the first implementation period, the state can take that into account in its URP analysis for the second implementation period." *Id.* For similar reasons, UARG also supports EPA's proposed clarification that "the baseline for determining whether there is deterioration on the 20 percent clearest days is the baseline period of 2000–2004." *Id.*

EPA also proposes that states can properly choose to update the URP to reflect certain changes, such as updates to IMPROVE data. *Id.* at 26953 & n.25. EPA also states that "the value of the baseline visibility conditions must be recalculated to be consistent with the approach used for the selection of the most impaired days in the SIP revision under preparation," referring to EPA's proposal to minimize the impacts of naturally occurring and non-U.S., or "international," emissions, discussed below in Section V of these comments. *Id.* The Draft Guidance, however, appears to reflect an assumption that such updates may be mandatory. *See, e.g.*, Draft Guidance at 42 n.49. UARG supports state discretion to make appropriate updates affecting calculation of the URP where the state determines that updates are warranted, but UARG urges EPA to make clear that states have discretion to decide whether, when, and how to make such updates.

In other respects, EPA's Proposed Rule, along with the Draft Guidance, creates the potential for confusion with respect to the meaning of the URP analysis. The existing provisions of the rule that have been in effect since 1999 reflect the policy that if a state sets an RPG for a Class I area that meets or exceeds the URP (*i.e.*, sets an RPG that reflects a rate of progress toward natural conditions that is at least as expeditious as the URP), then neither that state nor any other state need undertake any analysis of possible additional control measures for inclusion in the LTS with respect to that Class I area. The preamble to the existing rule reflects and describes this approach:

> . . . [T]he State must identify the uniform rate of progress over the 60 year period that would be needed to attain natural background conditions by the year 2064. For the example case . . ., where 18 deciviews is the amount for the 60-year period, this

> would result in a uniform rate of progress for each year of (18/60), or 0.3 deciviews for a year.
>
> . . . [Next,] the State must identify the amount of progress that would result if th[e] uniform rate of progress were achieved during the period of the first regional haze implementation plan. For example, if the first implementation plan covers a 10-year period, then for the above example, the State would identify a 3 deciview amount of progress over that time period.
>
> . . . [Next,] the State must identify and analyze the emissions measures that would be needed to achieve this amount of progress during the period covered by the first long-term strategy, and to determine whether those measures are reasonable based on the statutory factors. These factors are the costs of compliance with the measures, the time necessary for compliance with the measures, the energy and nonair quality environmental impacts of . . . compliance with the measures, and the remaining useful life of any existing source subject to the measures.
>
> . . . .
>
> *If the State determines that the amount of progress identified through the analysis is reasonable based upon the statutory factors, the State should identify this amount of progress as its reasonable progress goal* for the first long-term strategy, *unless it determines that additional progress beyond this amount is also reasonable*. *If* the State determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.

64 Fed. Reg. at 35732 (emphases added). Thus, under the existing rule, if a state determines that "the amount of progress" represented by the URP is "reasonable based upon the statutory factors," the state need do nothing further aside from "identify[ing] th[e] [URP] amount of progress as its reasonable progress goal." *Id.* Under these circumstances, the state's LTS for the Class I area in question would consist of whatever collection of existing or new measures the state has determined is projected to meet the URP for that area. The state would have to consider any additional measures for inclusion in the LTS only "[i]f" the state chose to make a determination, based on the statutory factors, that additional, beyond-URP progress is "also

reasonable" for that Class I area. *Id.* Accordingly, consistency with the URP creates a safe harbor for a state's RPG and associated LTS, such that the state may choose not to undertake any analysis of control measures where its RPG for a given Class I area is at or below the URP. The 2007 Guidance also reflects this policy.

On its face, the Proposed Rule does not appear to explicitly alter the policy established by the 1999 rules that meeting the URP is a safe harbor. The Proposed Rule would, however, require that, where a state establishes an RPG that "provides for a slower rate of improvement" than the URP, the state must demonstrate that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." Proposed 40 C.F.R. § 51.308(f)(3)(ii)(A); *see also* proposed 40 C.F.R. § 51.308(f)(3)(ii)(B). Because this proposed new requirement would impose obligations on states beyond those involved in conducting a basic reasonable progress analysis, it has no statutory basis and is unlawful.

Where this proposed new requirement applies to a state in which the Class I area is located, EPA further proposes to require a "robust" demonstration by the state, based on "document[ation]." 81 Fed. Reg. at 26954; proposed § 51.308(f)(3)(ii)(A). This vague requirement cannot serve as a basis for undermining congressionally granted state discretion.

Although the meaning and intent of this proposed requirement for "a robust demonstration" are not entirely clear, the proposed new provisions do at least appear to reflect the facts that, in establishing an RPG, a state may properly select a rate of progress that is less accelerated than the URP and that EPA may not second-guess or disapprove that state choice as long as the state documents a basis for it. UARG is concerned, however, that with its robust-demonstration criterion, EPA seeks to design—and, later, to "interpret" and apply—a burden-of-proof standard that a state must meet so that EPA may conclude that the state does *not* meet it and, on that basis, disapprove the state's SIP and impose the Agency's own conception of reasonable progress, as EPA did, for example, in its January 5, 2016 rule for Texas and Oklahoma. *Whatever EPA may mean by a "robust" demonstration, EPA may not impose its own policy choices as to what measures "would be reasonable to include in the long-term strategy" and may not disapprove a state choice on purported grounds that the state "demonstration" or documentation does not satisfy whatever EPA's conception of "robustness" or reasonableness happens to be, either in general or in a particular case.* Because of these problems, EPA should not finalize these proposed provisions. If the Agency nonetheless does so, it must make clear in the final rule that the provisions, if promulgated, are to be construed in light of fundamental principles of state primacy and discretion.

The Draft Guidance appears to go further than the Proposed Rule, stating that consistency with the URP does not provide a safe harbor. Draft Guidance at 18. Although the language used in the Draft Guidance is somewhat imprecise, EPA may be arguing there that the existing rule does not allow a state to rest its RPG determination on (i) a conclusion that the URP is reasonable for a given Class I area and (ii) a decision not to consider emission controls for potential inclusion in the LTS beyond the measures that are projected to meet (or exceed) the RPG for that area. For the reasons discussed above, such a view cannot be reconciled with EPA's language in the 1999 final rule preamble and should not be adopted.

V. EPA's Proposal To Revise the Way in Which Days Are Selected for Evaluation of Progress Toward Natural Visibility Conditions Must Properly Account for Emissions that Cannot Be Controlled by U.S. Anthropogenic Sources, Including All Naturally Occurring Emissions from U.S. Sources and All Non-U.S. Emissions.

As the Proposed Rule explains, natural events, such as wildfire or dust events, have overwhelmed visibility improvements from reduced emissions from man-made sources in a number of Class I areas. *Id.* at 26946. In some cases, the effects of natural events may completely dominate, and the effects of anthropogenic emissions may be insignificant or even virtually nonexistent in the first place. For that reason, EPA proposes rule revisions with the intent to exclude visibility impairment attributable to non-anthropogenic sources from consideration in the CAA's visibility program, proposing changes that would allow states to select "the 20 percent most impaired days based on anthropogenic impairment, rather than based on the highest deciview values due to all sources affecting visibility." *Id.* at 26955. UARG generally supports EPA's proposal to allow each state to select this approach *as an option*. The methodology EPA recommends that states use is addressed in the Draft Guidance. UARG's comments on the Draft Guidance will address this issue further. However, the text of the Proposed Rule does not limit states to the methodology EPA describes in the Draft Guidance. States should remain free to develop and use other approaches for identifying and excluding non-anthropogenic visibility impairment from consideration in the regional haze program. UARG also believes that a given state should not be required to make the same choice between EPA's proposed new approach and the traditional approach (or some other alternative approach) for all regional haze planning periods, but instead should be allowed to make a fresh judgment and choice on this matter for each planning period.

UARG also strongly supports EPA's reaffirmation of the principle that states need not "compensate for haze impacts from anthropogenic international emissions by adopting more stringent emission controls on their own sources."[4] *Id.* at 26956. This statement reflects EPA's policy as articulated in the preamble to the 1999 rules. *See* 64 Fed. Reg. at 35736. EPA proposes to allow states to remove such emissions from natural visibility conditions and, thereby, to adjust the calculation of the URP, but the Agency also proposes, as an alternative, to allow states to remove the influence of international emissions from baseline conditions, current conditions, and RPGs. 81 Fed. Reg. at 26956 & n.29. Under the Act and the existing rules, states have—and they must continue to have under any revised rules—full discretion to choose the methodology they conclude is most appropriate for their conditions. Under all circumstances, states should be able to remove the influence of international emissions from their RPGs and from consideration of the 20 percent most impaired days and the 20 percent least impaired (or "clearest") days in addition to their calculation of the URP.

EPA proposes to condition removal of such emissions on the Administrator's approval of the adequacy of a state demonstration as to the impact of such emissions, specifically stating that "[w]e believe that this adjustment should be permitted only if the Administrator determines the international impacts from anthropogenic sources outside the United States were estimated using scientifically valid data and methods." *Id.* at 26956. EPA also says it is "not convinced that such impacts can be estimated with sufficient accuracy at this time, in part due to great uncertainty about past, present and future emissions from sources in most other countries." *Id.*

It is troubling that, while EPA properly reiterates that it has never intended states to make up for the effects of international emissions, it offers the states no clear, specific pathway for ensuring that they do not end up doing so. Regardless of whether and to what extent EPA is able

[4] UARG understands EPA's references to "international" emissions to encompass emissions from any source that is located outside the boundaries of the United States.

to develop specific guidance on this issue on which states may rely,[5] EPA should recognize that states have broad leeway to develop and make use of their own tools to achieve the purpose of the CAA's regional haze provisions in requiring states to address visibility impacts only of those emissions they can control and in ensuring that they do not have to offset or compensate for impairment attributable to non-U.S. emissions.

UARG supports EPA's proposal to allow states to disregard emissions associated with wildland prescribed fires in evaluating an RPG's consistency with the URP. *See id.* at 26958. EPA's proposal, however, requires clarification. For instance, with respect to consideration of control measures for prescribed fires, EPA states:

> If prescribed fires in a state contribute meaningfully to impairment at a Class I area, the state is required to consider basic smoke management practices for prescribed fires in the development of its long-term strategy, regardless of whether or not those practices are currently being implemented, required by state law or mandated by an EPA-approved SIP. The state would be required to consider only smoke management programs as currently exist within the state. We believe that the state should in this situation give new consideration to the effectiveness of its smoke management programs in protecting air quality while also allowing appropriate prescribed fire for ecosystem health and to reduce the risk of catastrophic wildfires. The state could also consider the implementation of a new smoke management program.

Id. (footnote omitted). This statement could give rise to confusion because it may appear to be internally inconsistent and because it is unclear precisely what categories of smoke management practices EPA intends to require states to consider. UARG urges EPA to clarify its intent on this point. Further, UARG supports allowing states to adjust RPGs and visibility-condition

[5] States obviously are not in a position to develop any relevant emission inventory information with respect to non-U.S. emissions that EPA may believe are needed. That is EPA's job. *See, e.g.*, 64 Fed. Reg. at 35736 (assuring states that "EPA will work with the governments of Canada and Mexico"); 40 C.F.R. § 51.308(h)(3) ("Where the State determines that the implementation plan is or may be inadequate to ensure reasonable progress due to emissions from sources in another country, the State shall provide notification, along with available information, to the Administrator.")

calculations to reflect the impact of all prescribed fires. *See id.* at 26959 & nn.37, 38. The Proposed Rule does not provide a valid basis for distinguishing between wildland prescribed fire and other types of prescribed fire, including prescribed fire on commercial and private lands. Indeed, the same land and resource management considerations EPA describes with respect to wildland management apply with equal force to other categories of lands.

VI. EPA Properly Proposes To Conclude that Revisions to the BART Rules Are Not Necessary, but EPA Cannot Limit States' Discretion Regarding Whether or Not To "Re-Assess" BART Sources for Possible Reasonable Progress Controls.

The Proposed Rule states that a particular focus of the first implementation period for the regional haze program was the BART requirement for certain categories of sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962. *Id.* at 26947. The CAA makes clear, as EPA has said many times, that BART is a one-time determination that is not to be revisited in subsequent implementation periods. EPA reiterates that point in the Proposed Rule. *Id.* For that reason, EPA properly concludes that no revisions to the BART provisions of the regional haze rule are necessary. UARG agrees with this conclusion.

Nevertheless, EPA states that

> BART-eligible sources may need to be re-assessed for additional controls in future implementation periods under the CAA's reasonable progress provisions. Specifically, we anticipate that BART-eligible sources that installed minor controls (or no controls at all) will need to be reassessed. States should treat BART-eligible sources the same as other reasonable progress sources going forward.

Id. UARG agrees that a state *may choose* to reassess for reasonable progress purposes one or more BART-eligible sources that were not required to install controls (or that installed what EPA calls "minor" controls). *Id.* However, EPA does not have authority to dictate to states as to whether any given source, or any category of sources, "need[s] to be reassessed" for reasonable progress purposes. *Id.* That is a matter within each state's discretion. Equally important, the

Act's reasonable progress provisions do not require states to undertake source-by-source evaluations for reasonable progress purposes, and any final revisions to the rules should reflect that basic principle.

VII. EPA Should Terminate the RAVI Program, but If It Does Not Do So, It Must in Any Event Ensure that Any Revisions to the RAVI Rules Effectuate Coordination with Regional Haze Planning Efforts and Streamline Implementation of RAVI Requirements Without Unnecessarily or Unlawfully Expanding the RAVI Program's Scope or Diminishing the Role of States in Preference to the FLMs.

EPA says it proposes "extensive changes" to the RAVI regulatory program with the asserted goals of improving coordination with the regional haze program and enhancing environmental protection. *Id.* at 26945-46, 26961-64. Some of EPA's proposed changes may indeed allow for improved coordination of RAVI and regional haze planning and may reflect a recognition of the need for EPA to conform its rules to the CAA principle of state discretion and flexibility. Other proposed changes, however, are ambiguous and could be interpreted—and, in fact, might be intended by EPA—to unnecessarily and unlawfully expand the scope of the RAVI program or to diminish the role of states in preference to that of the FLMs.

At the outset, UARG emphasizes that the RAVI program—which has very rarely resulted in imposition of any additional emission controls—has outlived whatever usefulness it arguably may have had at one time. In sharp contrast to 1980, when EPA promulgated rules establishing the RAVI program—with regional haze regulations still nearly two decades in the future—today the regional haze program is well-established and, along with CAA permitting programs, addresses visibility impairment at protected Class I areas comprehensively. UARG is not aware of any reason (and EPA gives none) for continuing the RAVI program and notes that states, in comments in this rulemaking, question the need for any RAVI program. *See, e.g.,* Comments of the Air Pollution Control Division of the Colorado Department of Public Health & Environment, Docket ID No. EPA-HQ-OAR-2015-0531-0338, at 2 (Aug. 1, 2016) ("Colorado Comments")

(“Considering the visibility protections afforded through the implementation of Regional Haze and Prevention of Significant Deterioration programs, along with the infrequent application of RAVI, where only five Federal Land Manager RAVI certifications have occurred over the past 36 years, it may make sense to consider whether RAVI is still a necessary requirement.”) (footnote, listing the five RAVI certifications, omitted); Comments of the Virginia Department of Environmental Quality, Docket ID No. EPA-HQ-OAR-2015-0531-0216, at 4 (June 30, 2016) (“The need for the expansion of the RAVI program is unclear as the Regional Haze program has improved visibility in most Class I areas significantly. Individual facilities and sources identified under RAVI would be included in reasonable progress analyses in this next round of Regional Haze planning so that the existence of both programs addressing visibility impairment in Class I areas appears to be duplicative. Rather than expanding the RAVI program, [Virginia] requests that EPA examine the need for a RAVI program and whether such a program can be streamlined out of SIPs for most, if not all, states.”) In short, EPA should amend its rules to end the RAVI program.

If, however, EPA retains the RAVI program in some form, UARG supports several clarifications and changes included in the Proposed Rule. The proposed change to make RAVI requirement reviews unnecessary unless a certification of visibility impairment has been made is reasonable. UARG also agrees that an FLM certification “would not create a definite state obligation to adopt a new control requirement” but—at most—would create an obligation “only to submit a SIP revision that provides for any controls necessary for reasonable progress.” *Id*. at 26962. UARG emphasizes that the decision as to whether any controls—and, if so, which kinds of controls—are “necessary for reasonable progress” is a question for each state to determine in its discretion and is not open for second-guessing by EPA. The Proposed Rule also states that "[i]t would be the EPA, not the certifying FLM, that would determine whether the responding SIP is adequate and the response reasonable." *Id.* Although UARG agrees that the FLM cannot determine whether a "responding SIP" is or is not adequate and reasonable, UARG does not agree that EPA constitutes a "roving commission," *Michigan v. EPA*, 268 F.3d 1075, 1084 (D.C. Cir. 2001), to decide, based on the Agency's own views and policy preferences, what state responses are "reasonable." The responsibility to make that determination is one entrusted to the state and one that EPA cannot validly second-guess.

Indeed, UARG believes that any certification of RAVI should have the effect only of providing a recommendation to the state that the state may consider in determining whether and in what respect a revision to the SIP may be appropriate. *See, e.g.*, Comments of the State of Michigan Department of Environmental Quality, Docket ID No. EPA-HQ-OAR-2015-0531-0339, at 1 (Aug. 4, 2016); *see also, e.g.*, Colorado Comments at 2, 3. A RAVI certification should not impose any binding obligation on a state (or on EPA). At a minimum, EPA should revise the proposed text of 40 C.F.R. § 51.302(b), *see* 81 Fed. Reg. at 26969-70, by: (i) changing the phrase "shall revise its regional haze implementation plan" to "shall consider revising its regional haze implementation plan"; and (ii) revising proposed paragraph (b)(1) to read:

> A determination, based on the state's consideration of the factors set forth in § 51.308(d)(1)(i)(A) (and, at the state's election, the degree of improvement in visibility which may reasonably be anticipated to result from the use of any control measure or measures), as to whether any control measure or measures are necessary and appropriate with respect to the source or sources in order for the plan to make reasonable progress toward natural visibility conditions in the affected Class I Federal area;

In addition, it is important for EPA to revise the proposed text of 40 C.F.R. § 51.302(b)(2) and (b)(3) to clarify and reinforce EPA's point that the state has no obligation to revise its SIP to adopt any control measures. This could be done, for example, by inserting the phrase "if any" after "control measures" and "schedules for compliance" in paragraph (b)(2) and after "emission limitations" in paragraph (b)(3).

Further, the text of proposed 40 C.F.R. § 51.302(c) might be subject to being misconstrued as suggesting that if an FLM RAVI certification identifies "a BART-eligible source," then the state must revise its SIP to include BART or BART-alternative emission limits or other measures for that source if there is no EPA-approved BART SIP that is "in effect as of the date of the certification . . . [and that] address[es] the BART requirement for that source." *Id.* at 26970. EPA should revise the proposed rule text to make clear that there is no obligation to include BART or BART-alternative emission limits or other measures for such a BART-eligible source if the state has determined (either before or after the date of the RAVI certification) that that source is not subject to BART because it does not "emit[] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area." 40 C.F.R. § 51.308(e)(1)(ii). The determination of whether or not a BART-eligible source is subject to BART is reserved to the state, *Corn Growers*, 291 F.3d at 8, and thus may not under any circumstances be pretermitted by an FLM certification; the clarifying rule-text revision recommended here is appropriate to reinforce and reconfirm that fundamental principle and to avoid any confusion about whether the regulation conforms to the Act and congressional intent. In addition, EPA should make clear in this provision that under section 51.302(c), the state would not have any obligation to address BART for a given source if BART for that source were already addressed in a FIP, a scenario that the proposed regulatory text of this provision does not appear to expressly address.

UARG supports (although with the caveat that the proposed rule text revisions discussed above in relation to BART are needed) EPA's proposed determination that "a reasonably attributable visibility impairment certification for a BART-eligible source prior to the EPA's approval of a state's BART SIP for that source does not impose any substantive obligation on a state that is over and above the BART obligation imposed by § 51.308." 81 Fed. Reg. at 26962. UARG also supports EPA's determination that "a reasonably attributable visibility impairment certification of a BART-eligible source after the state's BART SIP for that source has been approved by the EPA does not trigger a requirement for a new BART determination based on the five statutory factors for BART." *Id.*

Other proposed changes are objectionable or problematic. As discussed further below, EPA proposes revisions that would appear to have the effect of expanding (or at least that could create the possibility that they could be exploited to expand) the scope of the RAVI program beyond—perhaps far beyond—the issue of plume blight for which the program was intended. EPA also proposes to apply the RAVI program to all states, instead of only states that have Class I areas. Further, the proposed revisions could be interpreted to improperly limit state authority, expand the role of the FLMs without authority, and impose problematic deadlines for state action. Each of these issues is discussed below.

As EPA notes, the RAVI program was designed when technology did not allow for comprehensive evaluation of regional haze and when "visual observation of 'plume blight' was the main method of determining whether a source was affecting a mandatory Class I area." *Id.* at 26961. It is not clear, however, that in these proposed revisions EPA intends to keep the focus of the RAVI program on plume blight. Indeed, some of the proposed changes suggest that EPA may be trying to expand the program's scope. EPA states, for instance that

> advances in ambient monitoring, emissions quantification, emission control technology and meteorological and air quality modeling that have occurred in the decades since 1980 make clear

> that modeling is one possible technique for determining that reasonably attributable visibility impairment is occurring.

Id. at 29692. But expanding the RAVI program in a way that would allow FLMs (or EPA) to rely on modeled visibility impacts would likely blur the distinction between the RAVI and regional haze programs, a development that would, if anything, provide additional support to terminating the RAVI program, as discussed above. If EPA does retain the RAVI program but allows modeling as a technique for identifying RAVI, the Agency would need to explain what purpose is served by maintaining a RAVI program as a distinct program from the regional haze program.[6]

EPA also proposes to expand RAVI requirements to all states covered by the regional haze program, *id.* at 26961, but does not provide a reasonable or persuasive basis for doing so. EPA says it "believes these changes would strengthen the visibility program and are appropriate in light of the evolved understanding that pollutants emitted from one or a small number of sources can affect Class I areas many miles away." *Id.* at 26961-62. Similarly, EPA proposes new regulatory language to address hypothetical situations where RAVI sources may be located in different states than the state in which the visibility impairment occurs. *See id.* at 26962. Particularly in light of the fact that EPA points to no such actual situations, these proposed rule changes suggest EPA may be seeking to alter the nature of the RAVI program in a way that gives rise to further questions about the viability of or need for a separate RAVI program distinct from the regional haze program.

[6] For instance, if an observable or measureable "event" can be shown to be predominantly caused by a single source or a small, discrete group of sources, such a situation arguably could be distinguishable from more generalized visibility impairment caused by a large number of sources. As stated above, however, such occurrences are likely to be rare in light of the existence and effects of other programs, including the reasonable progress program.

EPA's proposed revision to the definition of "reasonably attributable" also threatens to expand improperly the scope of the RAVI program. EPA acknowledges that it is attempting to limit state authority to determine which techniques form appropriate bases for a RAVI certification. *Id.* at 26962 ("This change would remove the current implication that only a state can determine what techniques are appropriate, even though the FLMs are charged with certifying reasonably attributable visibility impairment."). States, not EPA or the FLMs, should make these decisions. This proposed revision could improperly cede significant control of this program to FLM agencies, which are not authorized to exercise delegated powers on this issue under sections 169A and 169B of the CAA. Far from expanding the FLMs' role, EPA's regulations need to reflect that FLM authority under the visibility program is narrowly circumscribed. Indeed, Congress specifically created limited, narrowly defined roles for FLMs under the CAA, and EPA cannot alter Congress's decision on that matter. Section 169A of the CAA sets out purposely limited areas of authority for FLMs under the visibility program. For example, that provision authorizes the Secretary of the Interior to identify and to revise, "[f]rom time to time," the list of mandatory Class I areas in which visibility is an important value. CAA § 169A(a)(2). Section 169A empowers FLMs to delay or nullify the effectiveness of a special source exemption from BART requirements. *Id.* § 169A(c)(3). And section 169A requires a state to consult with the appropriate FLMs before it holds a public hearing on a regional haze SIP. *Id.* § 169A(d).

Where Congress has intended a broader role for the FLMs in implementing CAA requirements, it has said so explicitly, including with respect to visibility protection. Section 165 of the Act, which addresses permitting of new sources that in some cases may have the potential to affect visibility in Class I areas, gives FLMs clearly defined regulatory responsibilities that are not dissimilar from the ones EPA here proposes to add to the regional haze rule. Those statutorily assigned responsibilities in section 165 include authority to determine that a proposed major emitting facility "may cause or contribute to a change in the air quality" in a Class I area, and to "identify[] the potential adverse impact of such change," and thereby prevent issuance of a permit under certain statutorily specified circumstances. *Id.* § 165(d)(2)(C)(i), (ii). Section 165 also gives FLMs authority to certify that no adverse impact on air quality-related values, "including visibility," will occur, thereby authorizing issuance of a permit. *Id.* § 165(d)(2)(C)(iii).

"[W]here Congress includes particular language in one section of a statute but omits it in another . . . , it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Keene Corp. v. United States*, 508 U.S. 200, 208 (1993) (quoting *Russello v. United States*, 464 U.S. 16, 23 (1983)). Congress excluded the type of role that EPA's proposed rule revisions would hand to the FLMs in the context of the RAVI program, and neither EPA nor any other regulatory agency may lawfully assign power to other agencies to which Congress has not delegated authority. In fact, when EPA promulgated its 1980 rule allowing FLMs to certify RAVI and requiring states to respond to FLM certifications in SIP actions, EPA went to—indeed, beyond—the outer limits of its statutory authority insofar as it purported to give FLMs authority in the section 169A visibility program that nowhere appears in the text of section 169A itself.

By proposing to expand and significantly alter the nature of the FLM certification role, the Proposed Rule reopens this important statutory and legal issue. Expanding that role even further would be contrary to the statute. Thus, EPA should not adopt any rule revisions that would expand further FLMs' authority under the RAVI program and instead should adopt revisions to the rules that limit the role of the FLMs to the specific, narrow terms and circumstances set out in the text of section 169A. Moreover, if EPA's revised rules retain the RAVI program and retain any role for FLMs in certifications of RAVI, EPA should recognize that to the extent such a certification would trigger state obligations of any kind, the FLM would have to undertake public notice-and-comment rulemaking on the proposed certification. *Cf. Thomas v. New York*, 802 F.2d 1443, 1446-48 (D.C. Cir. 1986) (Scalia, J.).

In addition, EPA's proposed revisions to the RAVI SIP submittal deadline provisions pose several problems. EPA proposes three alternatives. According to EPA, each of these proposed alternatives is intended to further the Agency's goal of streamlining compliance with RAVI and coordinating that program with state obligations under the visibility rules' regional haze provisions. 81 Fed. Reg. at 26945, 26951.

EPA's proposed Option 1 "would retain the existing requirement for a state to respond to a reasonably attributable visibility impairment certification with a SIP revision within 3 years regardless of when the certification is made in the cycle of periodic comprehensive SIP revisions." *Id.* at 26963. This proposal would not appear to achieve either of EPA's stated goals in this area. Option 2 would coordinate a RAVI SIP submittal with either a comprehensive regional haze SIP revision or a five-year progress report. *Id.* But, as described by EPA, this option could provide a period as short as two years within which a state would have to develop, complete, and submit a RAVI SIP. This is not an adequate period, as EPA appears to recognize. It can be expected that states will need at least three years to complete the necessary analyses and rulemaking actions. Option 3, as described in the Proposed Rule, is extremely complex but would also provide, in some circumstances, two years, or perhaps even less, for state development of a RAVI SIP submittal. *Id.* Again, a minimum of three years is needed; providing any less time than that would be unreasonable and arbitrary.

Finally, EPA proposes changes to related provisions of the visibility rules addressing integral vistas. In addition to removing outdated language, which is one of EPA's proposed actions, the Agency requests comment on the possibility of removing all references to integral vistas from the rules. *Id.* at 26964. Such action is appropriate. As EPA notes, the existence of an integral vista imposes no clear substantive obligation on states. Moreover, only one integral vista was ever designated. Accordingly, the integral vistas provisions are unnecessary and outdated and should be rescinded.

VIII. EPA's Proposed Consultation Requirements Would Unnecessarily Burden States.

EPA proposes to alter the language of the regional haze rules' existing state-FLM consultation requirement to ensure that FLM input "occur[s] sufficiently early in the state's planning process to meaningfully inform the state's development of the long-term strategy." *Id.* at 26965. EPA proposes to modify the existing consultation requirement (*i.e.*, the requirement that consultation occur at least 60 days before a state's public hearing on a SIP) to make it more amorphous and, potentially, unnecessarily burdensome. Under the Proposed Rule, consultation would have to "occur early enough to allow the state time for full consideration of FLM input, but no fewer than 60 days prior to a public hearing or other public comment opportunity." *Id.* Further, EPA would establish a 120-day safe harbor that would be deemed "early enough." *Id.*

As to state-FLM consultation requirements, CAA § 169A simply provides that states are to consult with FLMs at some time "[b]efore holding the public hearing on the proposed revision" of a visibility SIP. CAA § 169A(d). The existing rules' requirement to consult at least 60 days before a public hearing more than adequately satisfies this statutory requirement. Indeed, EPA fails to offer for public review and comment any evidence or other support for any possible view that 60 days before a public hearing has proven insufficient. Thus, there is no reason or basis for revising this provision.

IX. EPA Should Eliminate the Five-Year Progress Report Requirement, but If EPA Retains That Requirement in Some Form, the Proposed Rule Revisions Should Further Minimize Unnecessary Burdens on States.

EPA's existing rules require each state to submit a progress report in the form of a SIP revision every five years after the date of the state's submittal of its comprehensive regional haze SIP. 40 C.F.R. § 51.308(g). EPA proposes to change the deadlines for submittal of these reports going forward "such that second and subsequent progress reports would be due by January 31, 2025, July 31, 2033, and every 10 years thereafter, placing one progress report mid-way between the due dates for periodic comprehensive SIP revisions." 81 Fed. Reg. at 26965. Although these deadline revisions are sensible in the context of the existing rules, UARG believes that rather than adopt half measures to mitigate unnecessary and counterproductive burdens on states' administrative resources, EPA should eliminate altogether the state progress report requirement in its rules.

Nothing in section 169A or section 169B of the Act requires interim progress reports, and EPA does not identify any statutory basis for them. EPA also does not show that they have been demonstrated to have significant utility. The requirement that states prepare and submit substantive regional haze SIP revisions periodically for each ten-year implementation period is adequate. A given state would of course be free to choose to prepare and submit to EPA (or simply to make available to the public) an interim progress report, but no state should be obligated to do so by EPA's rules.

If EPA retains the progress report requirement at all, the proposed date changes are appropriate in that they properly reflect the proposed revision to the submittal date for the reasonable progress SIP for the second implementation period. EPA also proposes to eliminate the requirement that states submit five-year progress reports as SIP revisions. EPA's purported basis for this proposal is conservation of limited state resources. *See id.* at 26966. UARG supports that goal and agrees that there is no reason progress reports must take the form of SIP revisions; however, it is doubtful that this change on its own will appreciably reduce state burdens. For instance, EPA proposes to retain requirements that states consult with FLMs in advance on their progress reports and that states offer the public an opportunity to comment on draft progress reports before states make them final. *Id.* at 26945. EPA states that these requirements currently exist with respect to the five-year progress report and that EPA is not changing them in substance. *Id.* No statutory basis exists, and EPA identifies none, for requiring states to consult with FLMs with respect to reports that are not SIPs or SIP revisions. The net result of the proposed revisions appears to be the retention of the most burdensome aspects of the progress report requirement. UARG therefore encourages EPA to revise this aspect of its proposal to provide significant, and needed, tangible relief to states—which will be subjected to an extraordinary workload due to other aspects of the Proposed Rule—by eliminating the progress report requirements entirely.

EXHIBIT 2

COMMENTS OF THE UTILITY AIR REGULATORY GROUP ON EPA'S DRAFT GUIDANCE ON THE DEVELOPMENT OF MODELED EMISSION RATES FOR PRECURSORS (MERPs) AS A TIER 1 DEMONSTRATION TOOL FOR OZONE AND $PM_{2.5}$ UNDER THE PSD PERMITTING PROGRAM

HUNTON & WILLIAMS LLP
LUCINDA MINTON LANGWORTHY
2200 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20037
(202) 955-1500

COUNSEL FOR THE UTILITY AIR REGULATORY GROUP

MARCH 31, 2017

COMMENTS OF THE UTILITY AIR REGULATORY GROUP ON EPA'S DRAFT GUIDANCE ON THE DEVELOPMENT OF MODELED EMISSION RATES FOR PRECURSORS (MERPs) AS A TIER 1 DEMONSTRATION TOOL FOR OZONE AND $PM_{2.5}$ UNDER THE PSD PERMITTING PROGRAM

On December 2, 2016, the United States Environmental Protection Agency ("EPA" or "Agency") made available for public comment draft guidance detailing a recommended process for permit applicants and permitting authorities to use in assessing the impact of a proposed major new or modified source of emissions of precursors to ozone and/or fine particulate matter ("$PM_{2.5}$") on levels of those pollutants in ambient air. EPA, "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program," EPA-454/R-16-006, https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf ("Draft Guidance"). These are the comments of the Utility Air Regulatory Group ("UARG") on that Draft Guidance.[1]

UARG believes that MERPs are consistent with the new source permitting requirements of the CAA,[2] and, if further developed as discussed below, will be useful in addressing requirements for sources that emit precursors of ozone and $PM_{2.5}$ in accordance with recently-promulgated revisions to EPA's Guideline on Air Quality Models ("Appendix W").[3] To improve the usefulness of MERPs for this purpose, however, these comments explain that EPA must develop them further, as discussed below. Once they have been adequately developed, UARG urges EPA to incorporate them as regulations, perhaps by referencing them as a screening model in Appendix W.

[1] UARG is an ad hoc, not-for-profit association of individual electric generating companies and national trade associations. UARG's purpose is to participate on behalf of its members collectively in EPA's rulemakings and other Clean Air Act ("CAA" or "Act") proceedings that affect the interests of electric generators and in litigation arising from those proceedings.

[2] 42 U.S.C. §§ 7401, *et seq.* Further citations to the Act in these comments will be given to the sections of the Act itself.

[3] 82 Fed. Reg. 5182 (Jan. 17, 2017) (to be codified at 40 C.F.R. Pt. 51, App. W).

I. MERPS ARE AN IMPORTANT COMPONENT OF A FUNCTIONAL PERMITTING PROGRAM FOR MAJOR NEW OR MODIFIED SOURCES THAT EMIT PRECURSORS OF OZONE AND $PM_{2.5}$.

The Prevention of Significant Deterioration ("PSD") program of the Act requires an owner or operator to obtain a permit for a proposed major emitting facility (or a facility for which a major modification is planned) in an area not designated nonattainment for a particular pollutant.[4] In its application for such a permit, the owner or operator must demonstrate:

> that emissions from construction or operation of such facility will not cause, or contribute to air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, [or] (B) national ambient air quality standard in any area air quality control region . . . .[5]

Appendix W specifies the modeling techniques, including both air quality models and screening approaches, that should be used for making these demonstrations. Until recently, Appendix W said that if it was necessary to quantify the impact of a single source on levels of ozone or $PM_{2.5}$ in ambient air, as would be required for a PSD permit application, the most suitable approach should be selected on a case-by-case basis.[6] Recent revisions to Appendix W, however, adopt a new two-tiered approach to assessing the impact of single sources on either ozone or $PM_{2.5}$. For both ozone and $PM_{2.5}$, "existing technical information," possibly paired with supplemental analysis, may be adequate for a Tier 1 analysis, but, in the absence of such information, a Tier 2 analysis using chemical transport modeling is now required.[7] Use of such a

[4] CAA § 165(a)(1).

[5] CAA § 165(a)(3). EPA has promulgated National Ambient Air Quality Standards ("NAAQS") for both $PM_{2.5}$ and ozone. 40 C.F.R. §§ 50.7, 50.9, 50.10, 50.13, 50.15, 50.18. The Agency has also promulgated maximum allowable increases, known as "increments," for $PM_{2.5}$ *Id.* §§ 51.166(c), 52.21(c). No increments have been adopted for ozone.

[6] 40 C.F.R. Pt. 51, App. W, §§ 5.2.1c., 5.2.2 d (2016).

[7] 82 Fed. Reg. at 5213-14 (to be codified at 40 C.F.R. Pt. 51, App. W, §§ 5.3.2, 5.4.2).

chemical transport model is complicated, time-consuming, and costly.[8] Although Congress did not intend the PSD program to prevent economic growth and development,[9] requiring chemical transport modeling will delay, and may even dissuade companies from developing, new or expanded facilities. Thus, to ensure that PSD permitting requirements do not unnecessarily impede economic growth, it is vital that EPA identify tools that source owners and operators can use for a Tier 1 analysis that satisfies the requirements of section 165(a)(3) of the Act in lieu of requiring use of a chemical transport model. MERPs are intended to be such a tool.[10]

II. MERPS ARE CONSISTENT WITH THE ACT.

Although some have questioned their legality,[11] in UARG's view MERPs are consistent with the Act's requirements for PSD permitting. For the reasons set forth below, UARG finds that MERPs comport with congressional intent for the PSD program, as well as the Act's text and structure. UARG urges EPA to adopt a clear explanation of the legal basis for MERPs at the time it finalizes its MERPs program.

In adding PSD permitting requirements to the Act in 1977, Congress sought "to protect public health and welfare from any actual or potential adverse effect which [the Administrator] . . . anticipate[s]" may occur and "to assure that any decision to permit increased air pollution in any area [other than a nonattainment area] . . . is made only after careful evaluation of all the

---

[8] EPA has provided guidance to be followed for such modeling that illustrates its complexity. EPA, Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and $PM_{2.5}$, EPA-454/R-16-005 (Dec. 2016), EPA-HQ-OAR-2015-0310-0172. This guidance explains that among the complexities associated with use of chemical transport models are requirements for use of a prognostic meteorological model, for a fine grid of receptors "in all directions surrounding a project source to capture meteorological and chemical variability" at distances that may exceed 50 km, and for a model performance evaluation. *Id.* at 13, 15, 18.

[9] The PSD program is intended "to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources." CAA § 160(3).

[10] According to EPA, "MERPs may provide a simple way to relate maximum downwind impacts with an air quality concentration threshold that is used to determine if such an impact causes or contributes to a violation of the appropriate NAAQS." Draft Guidance at 20. EPA has specifically described MERPs "as a Tier 1 demonstration tool for permit-related programs." 82 Fed. Reg. at 5193.

[11] *See* Comments of Earthjustice, (Oct. 27, 2015), EPA-HQ-OAR-2015-0310-0115.

consequences."[12] At the same time, however, Congress also made clear its intent that economic development continue.[13] To avoid excessively hampering development, Congress limited the prohibition on deterioration of air quality to "significant deterioration," and only subjected "major emitting facilities" to PSD permitting requirements.[14] Further, Congress warned these permitting requirements should not create unnecessary "bureaucratic delay."[15]

Congress chose not to prescribe how an owner or operator would demonstrate that a proposed source "will not cause, or contribute to" a NAAQS violation or increment exceedance. In particular, Congress did not define either the phrase "cause, or contribute to," or the terms "cause" and "contribute" in the Act. Instead, Congress directed EPA to fill in the details, instructing the Administrator to "promulgate regulations respecting the analysis required."[16] Consistent with this congressional direction, MERPs give meaning to the "cause, or contribute to" language of the PSD permitting program in the specific context of sources whose emissions include precursors to ozone and $PM_{2.5}$.[17]

MERPs are analogous to EPA's Significant Emission Rates ("SERs"), a long-standing regulatory approach that exempts sources with emissions less than a specified level from aspects

[12] CAA § 160(1), (5).

[13] CAA § 160(3).

[14] CAA § 165(a).

[15] S. Rep. No. 95-127, at 32 (1977), *reprinted in* 3 Comm. On Env't & Pub. Works, A Legislative History of the Clean Air Act Amendments of 1977, at 1371, 1406 (1979).

[16] CAA § 165(e)(3).

[17] Even if Congress had not directly authorized EPA to delineate the required analysis, EPA would have authority to interpret the undefined and ambiguous "cause, or contribute to" language. In particular, the term "contribute to" has been found to be ambiguous in other aspects of the Act. *See, e.g., Catawba Cty. v. EPA*, 571 F.3d 20, 35 (D.C. Cir. 2009) (per curiam); *Envt'l Def. Fund, Inc. v. EPA*, 82 F.3d 451, 459 (D.C. Cir. 1996) (per curiam). EPA is entitled to implement its own interpretation of ambiguous "cause, or contribute to" phrase in section 165(a)(3) of the Act. *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2439 (2014) ("[W]hen an agency-administered statute is ambiguous with respect to what it prescribes, Congress has empowered the agency to resolve the ambiguity."). Furthermore, EPA's interpretation of such ambiguous language need not be the only possible one, as long as it is reasonable. *Miss. Comm'n on Envtl. Quality v. EPA*, 790 F.3d 138, 151 (D.C. Cir. 2015) (per curiam).

of PSD permitting,[18] EPA established SERs in 1980 as an exercise of its inherent authority to specify *de minimis* exemptions from certain PSD requirements.[19] The United States Court of Appeals for the District of Columbia Circuit has long recognized such a "permissible . . . exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*," particularly where "the literal terms of a statute [would] mandate pointless expenditures of effort."[20] SERs reflect EPA's recognition that "there is no practical value in conducting an extensive PSD review" when a source's emissions are sufficiently low.[21]

MERPs employ the same *de minimis* authority to exempt sources with emissions of precursors of ozone and $PM_{2.5}$ that are below specified levels from extensive, Tier 2 PSD demonstrations. MERPs, like SERs, are a straightforward application of EPA's *de minimis* exemption authority. MERPs are specified such that facilities whose emissions fall below them will not cause or contribute to a NAAQS or increment violation. They reflect recognition that requiring time-consuming and costly chemical transport modeling to estimate the downwind impacts for such a facility would require "pointless expenditures of effort." MERPs represent a reasonable solution to ensuring the preservation of clean air resources, while at the same time streamlining the permitting process and reducing the needless administrative and financial burden for those proposed facilities to demonstrate that they will not cause or contribute to a violation of a NAAQS or PSD increment.

[18] 40 C.F.R. §§ 51.166(b)(23), 52.21(b)(23).

[19] EPA, Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans, Final Rule, 45 Fed. Reg. 52676, 52705 (Aug. 7, 1980).

[20] *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1979).

[21] 45 Fed. Reg. at 52705.

III. EPA SHOULD CLARIFY ITS MERPS GUIDANCE TO ENHANCE ITS USEFULNESS.

Although UARG supports MERPs as appropriate and legal tools for addressing PSD permitting requirements for facilities that emit precursors to ambient ozone and $PM_{2.5}$, UARG is concerned that, in its present form, the Draft Guidance is less useful than it could and should be. Specifically, UARG recommends that the Draft Guidance be revised to (1) clarify the requirements for modeling to support development of MERPs, including further modeling by the Agency to support MERPs; (2) clarify the process for using existing modeling to develop area-specific MERPs; and (3) clarify the use of MERPs to address $PM_{2.5}$ increments.

A. EPA Should Clarify and Simplify Requirements for Modeling to Support Development of MERPs.

Although the Draft Guidance includes in Tables A-1 through A-3 the results of EPA's modeling of several hypothetical sources in three regions of the United States, it clearly contemplates additional modeling by permit applicants or permitting authorities to develop MERPs.[22] It provides little clarity concerning the modeling that would be required, however, noting only that "[a] modeling protocol should be developed and shared with the EPA Regional Office," that such a protocol should provide for photochemical modeling, that there is no minimum number of sources that should be modeled, and that current and post-construction conditions should be represented.[23] If EPA actually expects others to conduct modeling for development of MERPs, it should provide greater specificity concerning the content of the modeling protocol. It should also specify the minimum requirements for MERPs development. As drafted this guidance seems to reflect an EPA wish list.

[22] Draft Guidance at 27, 42-74.
[23] *Id*. at 27.

Even if the Draft Guidance were to specify minimum modeling requirements for MERPs development, however, use of a chemical transport model would be required. Because use of such a model is time-consuming and burdensome, it is questionable whether anyone would perform such modeling unless the permitting of a facility or group of facilities was under consideration. Moreover, because development of a MERPs as a Tier 1 screening tool would require modeling at least as complex as that required for a Tier 2 demonstration, it is unclear why anyone would develop the Tier 1 tool rather than going straight to the Tier 2 demonstration.

UARG appreciates the modeling of single-source impacts on secondary pollutants already performed by EPA and included in Tables A-1 through A-3 of the Draft Guidance. Given the questions above about the likelihood of modeling by others to support development of MERPs, UARG urges EPA to perform additional modeling to support development of MERPs. Indeed, in the absence of such modeling by EPA, the first permit applicants will likely bear an outsized cost for modeling and later applicants will reap the benefits. Continued modeling by EPA would help to address this fundamental unfairness and would support the timely development of MERPs as a useful tool.

B. EPA Should Clarify the Process for Using Existing Modeling To Develop Area-specific MERPs.

Although the Draft Guidance indicates that "[p]re-existing modeling . . . that is deemed sufficient may be adequate" for development of MERPs applicable to an area,[24] the steps for developing the MERPs are not clear. How is the geographic area of interest to be defined? What source sensitivity simulations are required? What models are to be used? How does this modeling differ from the pre-existing modeling that can be relied upon or is this modeling for the purpose of whether the pre-existing modeling is adequate? The examples that the Draft

[24] *Id.*

Guidance provides based on the modeling done by EPA are helpful, but inadequate to answer these questions. Without such answers, neither a permit applicant nor a permitting agency can feel confident that EPA will conclude that a Tier 1 demonstration based on particular MERPs is adequate. To minimize the uncertainties highlighted by these questions, EPA should consider specifying initial MERPs for areas with pre-existing modeling. At the same time, because several conservative assumptions may underlie those MERPs,[25] a permit applicant or state should be allowed to refine a MERP, as appropriate for a particular project, with adequate technical justification,

C. EPA Should Clarify that MERPs Are Applicable to PSD Increments.

With regard to the relationship between MERPs and PSD increments, UARG understands that it is EPA's intent that MERPs may be used as a tool to demonstrate that a new or modified source will not cause or contribute to a violation of either a NAAQS *or* a PSD increment. This understanding is based on EPA's discussion of its intent to develop MERPs in its proposal of revisions to Appendix W.[26] Yet the Draft Guidance only once explicitly refers to the use of MERPs to demonstrate no violation of a PSD increment will occur.[27] UARG urges EPA both to clarify that MERPs are applicable to increments as well as to NAAQS and to conduct modeling for such MERPs as well as for NAAQS.

---

[25] MERPs derived from existing modeling may, for example by based on EPA's unnecessarily stringent Significant Impact Levels ("SILs"). *See* Hunton & Williams, LLP, Comments of the Utility Air Regulatory Group on EPA's Draft Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Deterioration Permitting Program (Sept. 30, 2016). Furthermore, these MERPs likely reference both worst-case modeled impacts from prototypical sources and an assumption that those impacts coincide in time and place with the existing ozone and $PM_{2.5}$ concentrations that are closest to the NAAQS.

[26] EPA, Proposed Rule, Revision to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter, 80 Fed. Reg. 45340, 45348 (July 29, 2015) ("As part of the separate rulemaking, the EPA intends to demonstrate that a source with precursor emissions (e.g., NOx and SO_2 for $PM_{2.5}$) below the MERPs level will have ambient impacts that will be less than the SIL and, thereby, provide a sufficient demonstration that the source will not cause or contribute to a violation of the PM 2.5 NAAQS *or PSD increments*." (emphasis added)).

[27] Draft Guidance, at 21 ("Consistent with EPA's draft guidance containing these SIL values, to the extent a permitting authority elects to use a SIL to quantify a level of impact that causes or contributes to a violation of the NAAQS or PSD increment(s), such values will need to be identified and justified on a case-by-case basis.").

IV. EPA SHOULD RECONSIDER PROMULGATING THE MERPS CONCEPT IN A REGULATION.

UARG recommends that, after providing the further clarification concerning MERPs discussed above, EPA reconsider its decision not to promulgate MERPs, as a concept, in regulations.[28] Appropriate MERPs regulations would increase the confidence of facility owners and operators that they can rely on MERPs in support of their applications for PSD permits. Furthermore, codifying the MERPs concept in regulations would enhance consistency in how MERPs are used.[29] UARG notes that SERs, which, as discussed above, are analogous to MERPs, are specified in the Agency's PSD regulations. MERPs could be treated similarly.

As an alternative to codifying the MERPs concept in the PSD regulations, however, EPA could consider revising Appendix W to specify the MERPs concept as screening models. Under Appendix W, a screening model "provide[s] conservative modeled estimates of the air quality impact of a specific source or source category based on simplified assumptions of the model inputs (e.g., preset, worst-case meteorological conditions)."[30] If a screening model suggests that a source may cause or contribute to a NAAQS or PSD increment violation, Appendix W continues, then a second tier of modeling should be done.[31]

The MERPs concept thus fits Appendix W's screening model description perfectly. The formula to develop a MERPs value provides a conservative estimate, because its inputs include a critical air quality threshold below which a permitting authority is confident that pollutant emissions will not lead to a NAAQS or PSD increment violation—a conservative number itself. The formula's other inputs come from previous modeling data that reflects the maximum

[28] *See* 82 Fed. Reg. at 5193.

[29] By codifying the concept as opposed to specific emission rates, EPA could allow for refinement of the MERPs themselves for particular application and provide for the evolution of MERPS due to improved information or changes in emissions or atmospheric conditions in an area.

[30] 82 Fed. Reg. at 5206 (to be codified at 51 C.F.R. Pt. 51, App. W, § 2.2b).

[31] *Id.*

impacts based on a year of data collection, which accounts for worst-case meteorological data occurring in that year. Based on these conservative inputs, the resulting MERPs values are indeed conservative thresholds for screening out sources not requiring additional, more sophisticated modeling for PSD permitting and qualifies as a screening model.[32]

V. CONCLUSION

In short, MERPs, which are consistent with statutory PSD permitting requirements, are vital elements of a permitting program for facilities that emit precursors of ozone and $PM_{2.5}$. Provisions concerning development and application of MERPs and the applicability of MERPs to increments require clarification, however, if the MERPs program is to function appropriately. Codification of MERPs either in EPA's PSD regulations or as screening models in Appendix W would provide additional clarity and consistency.

[32] The MERPs concept also satisfies Appendix W's criteria for use as a demonstration tool. Such tools "must be reflected in a codified regulation or have a well-documented technical basis and reasoning that is contained or incorporated in the record of the regulatory decision in which it is applied." 82 Fed. Reg. at 5207 (to be codified at 40 C.F.R. Pt. 51, App. W, § 2.2e). The Draft Guidance provides "a well-documented technical basis and reasoning" for using the MERPs concept as a demonstration tool in the PSD permitting program. The use of MERPs as a Tier 1 demonstration tool is therefore supported by existing regulations.

EXHIBIT 3

COMMENTS OF THE UTILITY AIR REGULATORY GROUP ON EPA 'S DRAFT GUIDANCE ON SIGNIFICANT IMPACT LEVELS FOR OZO NE AND FINE PARTICLES IN THE PREVENTION OF DETERIORATI ON PERMITTING PROGRAM

HUNTON & WILLIAMS LLP

LUCINDA MINTON LANGWORTHY
FELICIA H. BARNES
2200 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20037
(202) 955-1500

COUNSEL FOR THE UTILITY AIR REGULATORY GROUP

SEPTEMBER 30, 2016

COMMENTS OF THE UTILITY AIR REGULATORY GROUP ON EPA 'S DRAFT GUIDANCE ON SIGNIFICANT IMPACT LEVELS FOR OZO NE AND FINE PARTICLES IN THE PREVENTION OF DETERIORATI ON PERMITTING PROGRAM

As the Environmental Protection Agency ("EPA" or "Agency") has explained, the Agency has for many years relied on Significant Impact Levels ("SILs") as an element of its Prevention of Significant Deterioration ("PSD") program to assess (1) the geographic extent for any required modeling analysis; (2) whether a source needs to perform a cumulative analysis; and (3) whether the results from the cumulative analysis indicate the source's impact causes or contributes to a violation of the NAAQS or PSD increments. EPA, Webinar Presentation on Draft Guidance on Ozone and Fine Particle ($PM_{2.5}$) Significant Impact Levels (SILs) for the Prevention of Significant Deterioration (PSD) Permitting Program 3 (Aug. 24, 2016), https://www.epa.gov/sites/production/files/2016-08/documents/webinar-ozone-pm25-sils-guidance-20160824.pdf. On August 1, 2016, EPA made available for public comment a draft memorandum specifying SILs for ozone and $PM_{2.5}$,[1] together with supporting legal and technical analyses. EPA, "Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program," https://www.epa.gov/nsr/forms/significant-impact-levels-ozone-and-fine-particles-prevention-significant-deterioration (last updated August 24, 2016).

The recommended SILs for the NAAQS were as follows:

- For the 8-hour ozone NAAQS, a SIL of 1.0 ppb;
- For the 24-hour $PM_{2.5}$ NAAQS, a SIL of 1.2 $\mu g/m^3$; and

[1] EPA released a revised memorandum on August 18, 2016 that corrected some of the SILs. Draft Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, EPA, to Regional Air Division Directors, 1-10 (Aug. 1, 2016, revised Aug. 18, 2016) ("Revised Memorandum"), https://www.epa.gov/sites/production/files/2016-08/documents/pm2_5_sils_and_ozone_draft_guidance.pdf.

- For the annual $PM_{2.5}$ NAAQS, a SIL of 0.2 $\mu g/m^3$.[2]

EPA also recommended SILs for the $PM_{2.5}$ increments, as follows:

- For the 24-hour $PM_{2.5}$ PSD Increment –
  - A SIL of 0.27 $\mu g/m^3$ for Class I areas; and
  - A SIL of 1.2 $\mu g/m^3$ for Class II and Class III areas;
- For the annual $PM_{2.5}$ PSD Increment –
  - A SIL of 0.05 $\mu g/m^3$ for Class I areas; and
  - A SIL of 0.2 $\mu g/m^3$ for Class II and Class III areas.[3]

These are the comments of the Utility Air Regulatory Group ("UARG") on the Revised Memorandum and EPA's materials supporting it.[4] UARG supports EPA's use of SILs in the PSD program because SILs are legally consistent with the Clean Air Act, 42 U.S.C. § 7401, *et seq.* ("Act" or "CAA"), and they facilitate efficient permitting of new or modified sources that do not threaten compliance with NAAQS or increments. UARG does, however, have concerns about the specific SILs that EPA is recommending because of their exceedingly low levels.

I. The SILs Program Is Consistent with the Act.

SILs are legally consistent with the text of the Clean Air Act, its structure and function, and Congressional intent. Congress added Part C of Title I, "Prevention of Significant Deterioration of Air Quality," to the Act in 1977 in part "to protect public health and welfare from any actual or potential adverse effect" the Administrator judges may occur even in an area attaining all of the NAAQS and "to assure that any decision to permit increased air pollution in

[2] Revised Memorandum at 10, Table 1.
[3] *Id.* at 11, Table 2.
[4] UARG is an ad hoc, not-for-profit association of individual electric generating companies and national trade associations. UARG's purpose is to participate on behalf of its members collectively in EPA's rulemakings and other CAA proceedings that affect the interests of electric generators and in litigation arising from those proceedings.

any area [other than one designated nonattainment] is made only after careful evaluation of all the consequences of such a decision." 42 U.S.C. §7470(1), (5), CAA § 160(1), (5). At the same time, however, Congress wanted "to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources." *Id.* §7470(3), CAA § 160(3). Congress recognized the necessity that development continue to occur.[5] It therefore did not prohibit all deterioration in air quality, only deterioration that was "significant." It did not subject all new sources to Part C's permitting requirements, only "major emitting facilities."[6]

For "major emitting facilities," Congress required the owner or operator to obtain a permit. It further required the owner or operator of the facility to demonstrate as a condition of that permit that emissions from the source would "not cause, or contribute to" a violation of a NAAQS or of an increment that was established by Congress or EPA to protect air quality. CAA § 165(a)(3). While imposing these permitting requirements, Congress cautioned against letting them create unnecessary "bureaucratic delay."[7]

Congress did not specify how an owner or operator was to demonstrate that its facility would not cause or contribute to a NAAQS or increment violation, only that such a demonstration was required. *Sierra Club v. EPA*, 705 F.3d 458, 465 (D.C. Cir. 2013). SILs provide a method by which an owner or operator can make the required demonstration for an appropriate source while minimizing unnecessary bureaucratic delay.

In guidance establishing an interim SIL for the 1-hour NAAQS for sulfur dioxide ("SO_2"), EPA explained:

[5] *See, e.g.,* S. Rep. No. 95-127, at 29, *reprinted in* 3 Envt'l Policy Div., Cong. Res. Serv., A Legislative History of the Clean Air Act Amendments of 1977, at 1403 (1979) ("Legis. Hist.").
[6] 42 U.S.C. §7475 (a), CAA § 165(a). The Act includes a lengthy definition of "major emitting facility." *Id.* § 7479(1), CAA § 169(1).
[7] S. Rep. No. 95-127, at 32, Legis. Hist. at 1406.

> This interim SIL is a useful screening tool that can be used to determine whether or not the predicted ambient impacts caused by a proposed source's emissions increase will be significant and, if so whether the source's emissions should be considered to "cause or contribute to" modeled violations of the new 1-hour SO_2 NAAQS.[8]

As this quote makes clear – and as is further elaborated in the Legal Support Memorandum that accompanies the Revised Memorandum[9] – SILs are a manifestation of "EPA's historic interpretation of the phrase 'cause, or contribute to,' as specifically used in the context of section 165(a)(3) of the CAA . . . ." Legal Memorandum at 1. As EPA has noted, "[T]he phrase 'cause, or contribute to' and the included terms 'cause' and 'contribute' are not defined in . . . the CAA." *Id.* at 2. Because the Act is ambiguous about the meaning of the phrase,[10] EPA is authorized to interpret it. *Utility Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2439 (2014) ("[W]hen an agency-administered statute is ambiguous with respect to what it prescribes, Congress has empowered the agency to resolve the ambiguity.").

Of course, EPA's interpretation of the ambiguous language must be reasonable. *Mississippi Comm'n on Envt'l. Quality v. EPA*, 790 F.3d 138, 151 (D.C. Cir. 2015). Here, the Agency's interpretation is, indeed, reasonable and ensures violations of the NAAQS and increments will not occur. First, the $PM_{2.5}$ and ozone SILs "represent a level of impact on

[8] Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, EPA, to Regional Air Division Directors 2 (Aug. 23, 2010), https://www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf.

[9] EPA, Legal Support Memorandum: Application of Significant Deterioration in the Air Quality Demonstration for Prevention of Significant Deterioration Permitting under the Clean Air Act (Draft Aug. 1, 2016), https://www.epa.gov/sites/production/files/2016-08/documents/pm2_5_sils_and_ozone_2060-za24_legal_document.pdf ("Legal Memorandum").

[10] The United States Court of Appeals has found the terms "contribute to" ambiguous in other CAA contexts. *See, e.g., Catawba County v. EPA*, 571 F.3d 20, 35 (D.C. Cir. 2009) (finding the phrase "contributes to" ambiguous in the context of defining the boundaries of a nonattainment area); *Envt'l Defense Fund, Inc. v. EPA*, 82 F.3d 451, 459 (D.C. Cir. 1996) (finding the phrase "contribute to" ambiguous in the context of transportation conformity plans under the Act).

ambient air quality that is insignificant or not meaningful." Revised Memorandum at 9.[11] Second, the permitting authority is required to consider on a case-by-case basis whether reliance on a SIL is warranted. *Id.* at 1, 10. Finally, if in a specific case concern remains that despite "a demonstration that a proposed source's impact is below the relevant SIL value at all locations," a source may contribute to a violation, further information may be required. *Id.* at 12. These provisions ensure that SILs will not be relied on to permit construction of a major emitting facility that would cause or contribute to a violation.

II. EPA's Approach to Establishing SILs for Ozone and $PM_{2.5}$ Is Reasonable.

To support the SILs in the Revised Memorandum, EPA released a Technical Support Document explaining its use of a new air quality variability at the design value to derive the levels for the SILs.[12] EPA developed this new approach to determine "if a 'significant ambient impact will occur' from the emissions from a proposed new or modifying major source." TSD at 38. Under EPA's approach, air quality impacts below the designated SIL values have an "insignificant impact" on the NAAQS or PSD increments, regardless of where they occur. EPA's approach uses the variability in monitoring data for $PM_{2.5}$ and ozone to determine what

[11] Although EPA asserts that the SILs "need not be based on inherent agency authority to establish a *de minimis* exception to section 165(a)(3) of the Act" Legal Memorandum at 9, the Agency could have cited such authority as the basis for its SILs (and, as discussed in Part III below, should have cited such authority to justify SILs more consistent with its long-standing approach to setting SILs). Agencies generally have "inherent" power to provide exemptions from an act's requirements when to apply the literal terms of the statute would "mandate pointless expenditures of effort." *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1979). Furthermore, while the D.C. Circuit vacated EPA's Significant Monitoring Concentrations for $PM_{2.5}$ because it found EPA lacked *de minimis* authority for them, *Sierra Club v. EPA*, *id.* at 469, the court declined to find that the Agency also lacked authority for SILs. *Id.* at 464. As a general matter, Congress did not intend the PSD provisions to be exceptionally rigid. Rather, they "contain[] a great deal of flexibility." Conference Report and Debates, Legis. Hist. at 367 (Statement of Sen. Stafford). SILs effectuate the flexibility specified by Congress for the PSD program.

[12] EPA, Technical Basis for the EPA's Development of Significant Impact Thresholds for PM2.5 and Ozone (July 2016), https://www.epa.gov/sites/production/files/2016-08/documents/pm2_5_sils_and_ozone_technical_basis_document.pdf ("Technical Basis Document" or "TSD").

level of an air quality impact would constitute a "*statistically insignificant* deviation from the inherent variability in air quality." TSD at 7. This approach identifies SILs that would be consistent, statistically speaking, with ambient levels that could have resulted from variation in air quality even without emissions from a new or modified source. As such, air quality impacts at or below these SIL values are actually not impacts at all, let alone significant ones. Those impacts simply cannot be deemed a cause of, or contribution to, a violation of a NAAQS or increment. Accordingly, EPA's approach provides one reasonable analytical pathway for permit applicants to demonstrate compliance with section 165(a)(3) of the Act.

Under EPA's approach, the chosen SILs represent changes in ambient air quality that are statistically indistinguishable from air quality values that would occur without any additional pollution. As such, these SIL values represent air quality impacts that are not statistically different from the pre-construction ambient levels. As EPA explained in the Technical Basis Document:

> This approach for quantifying an "insignificant" air quality impact is fundamentally based on the idea that an anthropogenic perturbation of air quality that is within a specified range may be considered indistinguishable from the inherent variability in the measured atmospheric concentrations and is, from a statistical standpoint, insignificant at the given confidence level.

TSD at 7.

In other words, changes in air quality below the SILs cannot be distinguished from no change at all, and certainly cannot be viewed as significant changes. Emissions that have an impact on ambient air quality below the SILs have impacts on air quality that are indistinguishable from the effect of existing variability. Thus, emissions that change ambient air quality below the SILs cannot be said to be causing or contributing to anything, let alone a

NAAQS or increment violation. This approach is consistent with CAA § 165(a)(3) and a reasonable methodology for permitting authorities to use in their PSD programs.

III. EPA's Present Approach To Setting SILs, Though Reasonable, Is Unnecessarily Conservative and Should Be Replaced by SILs Established Following the Agency's Long-standing Approach.

As discussed above, EPA's approach is one reasonable way to define "cause, or contribute to," for PSD permitting purposes. It is, however, a very conservative approach to identifying a threshold screening value for determining whether a potential impact on air quality is sufficiently significant that additional analysis is necessary.[13] Under EPA's approach, SILs are ambient air quality changes that are statistically indistinguishable from inherent variability (or essentially no effect at all). A major source meeting the SILs EPA has proposed will not cause any statistically detectable change to existing ambient air quality. Unfortunately, these SILs may be too small to be of practical assistance in streamlining the permitting process for many sources. Few sources are likely to be screened out from needing additional burdensome and costly analysis that would ultimately demonstrate there will be no causation of or contribution to a NAAQS or increment violation.[14] Accordingly, UARG recommends EPA consider using an alternative, less conservative approach to setting SILs to maximize their usefulness.[15]

---

[13] EPA's approach is rendered even more conservative by the Agency's suggestion that the SIL should always be compared to a source's "maximum impact." Revised Memorandum at 11. With the exception of the increment for the annual $PM_{2.5}$ NAAQS, the forms of the NAAQS and increments addressed by these SILs mean that violations are not judged by the maximum measured value. UARG recommends that EPA recommend comparison of the SIL to the value allowed by the NAAQS or increment. For example, in the case of the 24-hour $PM_{2.5}$ NAAQS, the SIL would be compared to "the 98th percentile 24-hour concentration, as determined in accordance with appendix N of [40 C.F.R. Pt. 50]. . . ." 40 C.F.R. §50.18(c).

[14] Even sources needing a PSD permit that do not require extensive modeling to establish that they will not cause or contribute to NAAQS or increment violations are required to use Best Available Control Technology. *See* 42 U.S.C. § 7475(a)(4), CAA § 165(a)(4).

[15] UARG is also concerned that EPA has not identified a model for individual sources of precursors of $PM_{2.5}$ or ozone that can, as a practical matter, be used for something other than a time-consuming and costly cumulative impact analysis.

EPA has never interpreted CAA § 165(a)(3) to require a showing that the major source will have *no effect at all*. Instead, as EPA states:

> [P]ermitting authorities may elect to read section 165(a)(3) of the Act to be satisfied when a permit applicant demonstrates that the increased emissions from the proposed new or modified source will not have a significant or meaningful impact on ambient air quality at any location where a violation of the NAAQS or PSD increment is occurring or may be projected to occur.

Legal Memorandum at 1. Thus, a proposed project can have a detectable effect, as long as it is not a significant or meaningful impact. *See In re Prairie State Generating Co.*, 13 E.A.D. 1, 139 (EAB 2006) ("Read in context, the requirement . . . to demonstrate that emissions from a proposed facility will not 'cause, or contribute to' air pollution in excess of a NAAQS standard must mean that some non-zero emission of a NAAQS parameter is permissible, otherwise such a demonstration could not be made.").

EPA has long interpreted section 165(a)(3) to allow a permitted source to have a small or trivial (i.e., detectible, non-zero) impact on air quality because such a trivial impact cannot be said to cause or contribute to a NAAQS or increment violation. As early as 1978, EPA explained that it did not intend the PSD program to require the permitting authority to address impacts "below certain levels." 43 Fed. Reg. 26379, 26398 (June 19, 1978). In 1980, EPA issued guidance explaining that "EPA continue[d] to apply th[is] significant impact concept" to PSD permitting. Memorandum from Richard G. Rhoads, Director, Control Programs Development Division, Office or Air Quality Planning and Standards, EPA, to Alexandria Smith, Director, Air & Hazardous Materials Division, Reg. X, at 1 (Dec. 16, 1980).

EPA reiterated that interpretation in 2010:

> A significant impact level (SIL) serves as a useful screening tool for implementing the PSD requirements for an air quality analysis. The primary

> purpose of the SIL is to serve as a screening tool to identify a level of ambient impact that is sufficiently low relative to the NAAQS or PSD increments such that the impact can be considered trivial or *de minimis*. . . . When a proposed source's impact by itself is not considered to be 'significant,' EPA has long maintained that any further effort on the part of the applicant to complete a cumulative source impact analysis involving other source impacts would only yield information of trivial or no value with respect to the required evaluation of the proposed source or modification.

Memorandum from Anna Marie Wood, Acting Director, Air Quality Policy Division, Office of Air Quality Planning and Standards, EPA, to Regional Air Division Directors 11 (June 28, 2010)("Wood NO_2 Memo").

Permits granted based on the use of these SILs that are at detectable levels have been upheld both by EPA's Environmental Protection Board,[16] and in federal court.[17] UARG is unaware of any instance of a source for which a permit was granted based on use of a SIL that was subsequently determined to have caused or contributed to a violation of a NAAQS or increment that existed at the time the permit issued. UARG therefore maintains that use of SILs at detectable levels remains a viable, legal approach for identifying sources that will not cause or contribute to a NAAQS or increment violation.

In practice, as acknowledged in the Revised Memorandum, EPA has frequently set SILs as a small percentage of a NAAQS. *See* Revised Memorandum at 8. That approach provides a SIL that is small, but at a detectable, non-zero level. In 2010, for example, EPA established an interim SIL for the 1-hour NO_2 standard that was 4% of the NAAQS. Wood NO_2 Memo at 12. The Agency similarly set an interim SIL for the 1-hour SO_2 NAAQS that was 4% of the NAAQS. Memorandum from Anna Marie Wood, Acting Director, Air Quality Policy Division, Office of Air Quality Planning and Standards, EPA, to Regional Air Division Directors 6 (Aug.

---

[16] *See, e.g., Prairie State,* 13 E.A.D. 1.

[17] *See, e.g., Sur Contra La Contamination v. EPA*, 202 F.3d 443 (1st Cir. 2000).

23, 2010). UARG maintains that this remains a valid approach to selecting a SIL, and one that produces a SIL at a detectable level that is not effectively zero. UARG urges EPA to return to this long-standing approach for setting SILs for ozone and $PM_{2.5}$.

IV. Conclusion.

In sum, UARG agrees with EPA that SILs are consistent with the requirements of the Act. Furthermore, SILs are a useful tool for demonstrating appropriate sources to use to demonstrate that they will not cause or contribute to a violation of a NAAQS or increment. The SILs set forth in EPA's Revised Memorandum result from a reasonable, but highly conservative, approach by the Agency for ensuring the protection of NAAQS and increments. UARG urges EPA instead to adopt more useful SILs using its long-standing approach of setting NAAQS as a small percentage of the NAAQS and increments for ozone and $PM_{2.5}$.

STREAMLINING PERMITTING AND REDUCING REGULATORY BURDENS FOR **DOMESTIC MANUFACTURING**

U.S. Department of Commerce

October 6, 2017

Table of Contents

Introduction 1
Summary of Recommendations 2
Issues Raised in Response to the RFI 4
Regulatory and Permitting Problems — Key Themes 4
Selection of Priority Specific Regulatory and Permitting Issues 6
Priority Regulatory and Permitting Issues 8
Overview of Regulatory Reform 29
Past Attempts at Regulatory and Permitting Reform 29
The Need for Collaboration between Regulators and Manufacturers 30
Review of Existing Regulations 34
Reforming the Permitting Process 35
New Rules: Improving the Rulemaking Process 41
Recommendations and Priority Areas for Reform 42
Priority Areas for Reform 43
Recommendations 48
Conclusion 49
Appendix 51

Introduction

Federal regulations impose enormous costs on America's businesses and working families. These costs burden virtually every sector of our economy, although the manufacturing sector is disproportionately hard hit. The direct costs on manufacturing companies were estimated by the National Association of Manufacturers (NAM) to be $138.6 billion as of 2014,[1] though this estimate does not include indirect negative effects on the U.S. economy such as reduced innovation and global competitiveness, lost investment, and significant job losses. Small businesses are also disproportionately burdened by excessive federal regulation.

As a nation, we can and must do better. That is why, on January 24, 2017, President Trump signed a Presidential Memorandum on *Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing*.[2] The Memorandum, which is one part of an Administration-wide regulatory reform agenda,[3] required the Secretary of Commerce, in coordination with other executive departments and agencies, to conduct outreach to stakeholders on the impact of federal regulations and permitting requirements on domestic manufacturing and to submit a report to the President setting forth a plan to streamline federal permitting processes and to reduce the regulatory burdens affecting domestic manufacturing.

For this report, the Department of Commerce sought input from stakeholders through a Request for Information (RFI) published in the Federal Register.[4] The RFI asked industry stakeholders to identify the most burdensome regulations and permitting requirements they face and requested feedback on how regulatory compliance and permitting could be simplified. This report reflects extensive, thoughtful comments received from U.S. manufacturers as well as upstream and downstream industries closely linked to the manufacturing sector.[5] It aggregates and summarizes many of the most important recommendations raised by industry and presents the Department's recommendations for streamlining the federal permitting processes and reducing the regulatory burdens that affect domestic manufacturing.

In response to the RFI, industry expressed clear support for the need to protect the environment, human health, and worker safety, but shared concrete, detailed concerns about how the federal government tries to achieve those objectives. Respondents identified numerous regulatory and permitting problems,

---

[1] W. Mark Crain and Nicole V. Crain, "The Cost of Federal Regulation to the U.S. Economy, Manufacturing, and Small Business," A Report for the National Association of Manufacturers, September 2014.
[2] 82 FR 8667 (January 24, 2017).

[3] President Trump has issued several executive orders that provide impetus and direction for regulatory reform efforts. These include EO 13771 on Reducing Regulation and Controlling Regulatory Costs, which directs departments and agencies to identify for elimination at least two regulations for every one new regulation issued; EO 13777, on Enforcing the Regulatory Reform Agenda, which requires agencies to designate a Regulatory Reform Officer (RRO) who is responsible for overseeing regulatory reform initiatives, and to establish a Regulatory Reform Task Force (RRTF); and EO 13683 which directs agencies to review regulations affecting the domestic energy industry and to appropriately reduce undue burdens to the development of domestic energy resources.
[4] 82 FR 12786 (March 7, 2017).

[5] This report focused on regulatory and permitting issues that directly impact the construction, operation or expansion of manufacturing plants. While focused on the manufacturing sector, upstream and downstream industries also submitted comments echoing the concerns of U.S. manufacturers and highlighting unique issues that they face. This report includes that input because regulatory barriers that adjoining industries experience can weaken production and investment in the domestic manufacturing sector.

including: onerous and lengthy permitting processes that increase cost, add uncertainty, and inhibit investment in new and existing manufacturing facilities; inadequately designed rules that are impractical, unrealistic, inflexible, ambiguous, or that show a lack of understanding of how industry operates; unnecessary aspects of rules, or unnecessary stringency, that are not required to achieve environmental or other regulatory objectives; overlap and duplication between permitting processes and agencies; and overly strict or punitive interpretations of guidance, policies or regulations that are often counter to a pro-growth interpretation. The Department identified 20 sets of regulations and permitting reform issues from the respondents as being a top priority for immediate consideration. See the section titled, "Recommendations and Priority Areas for Reform."

Despite numerous regulatory reform initiatives over the years, businesses continue to express concerns about increasing regulatory burdens. The fact that manufacturers continue to raise the same concerns, even after decades of regulatory reform efforts by the federal government, indicates a failure on the federal government's part to fully engage with regulated industries and fully understand the real-world impact of its regulations. There is a vital need for better dialogue and understanding between regulators and industry. In the meantime, the urgency for reform continues to grow. A 2017 NAM study states that most manufacturers perceive their regulatory burden to have increased significantly, such that reducing their current burden is at least as important as reducing the cost of new regulations.[6] We must do both.

Summary of Recommendations

The Department makes three major recommendations based on a thorough review of responses to the RFI.

Agency "Action Plans". Each agency's Regulatory Reform Taskforce (RRTF) should deliver to the President an "Action Plan" in response to all permitting and regulatory issues highlighted in the responses to the RFI, with particular attention to the "Priority Areas for Reform" section located at the end of the report.

Annual Regulatory Reduction Forum. There is no regular process for consultations with industry to identify specific actions the federal government can take to eliminate unduly burdensome regulations and accelerate permitting decisions. Thus, the Department recommends creating an annual, open forum for regulators and industry stakeholders to evaluate progress in reducing regulatory burdens.

Expanding the Model Process in FAST-41. The FAST Act[7] contains various provisions aimed at streamlining the environmental review process, with improved agency coordination through the creation of

[6] National Association of Manufacturers, "Holding US Back: Regulation of the U.S. Manufacturing Sector," prepared by Pareto Policy Solutions, LLC.
[7] Title 41 of the Fixing America's Surface Transportation Act of 2015 ("Fast-41", codified at 42 U.S.C. § 4370m) streamlines the Federal environmental review and permitting for certain infrastructure projects. FAST-41 created an interagency Federal Permitting Improvement Council (FPISC); established new procedures for interagency consultation and coordination practices; authorized agencies to collect fees to help speed the review and permitting process; and uses the Department of Transportation's "Permitting Dashboard" to track all covered projects.

a Coordinated Project Plan and a Permitting Dashboard. Covered projects will typically enjoy better coordination, transparency of approvals, and expedited permitting. The Department recommends that the Administration use existing authority to extend the use of streamlined permitting procedures in the FAST Act to any project that will result in a significant, immediate economic benefit to the United States. For example, consideration could be extended to funded, qualifying projects in a new "economically significant" category. Consideration should be extended to complex, funded manufacturing projects that are in late stages of development and that can demonstrate significant net direct and indirect benefits to the domestic economy. To be eligible for the current streamlining process, projects in this sector or category would still need to meet the definition of a "covered project" under FAST-41.

FAST-41 provides a model process that could be incorporated into other Federal legislation that governs Federal programs and requirements that apply to manufacturing facilities. To expand further the universe of manufacturing projects that benefit from streamlined regulatory approval processes, the Administration could work with members of Congress to both expand the definition of "covered project" under FAST-41 and to incorporate procedures similar to those found in FAST-41 in other legislation applicable to manufacturing projects.

The Department believes that these three recommendations, if executed promptly and with constant, aggressive leadership, will yield significant results. Set forth below is (i) a summary of issues raised in response to the RFI; (ii) an analysis relating to potential reforms; and (iii) specific recommendations and priority areas for reform.

Issues Raised in Response to the RFI

Regulatory and Permitting Problems — Key Themes

This section discusses priority regulatory and permitting issues that were identified from the RFI responses and related outreach.[8] Respondents did not question the need to protect the environment, human health, or worker safety but they expressed concern about how regulations are employed to achieve those objectives, including:

- Onerous and lengthy permitting processes that increase cost, add uncertainty, and inhibit investment in new and existing manufacturing facilities;
- Inadequately designed rules that are impractical, unrealistic, inflexible, ambiguous or lack understanding of how industry operates;
- Unnecessary aspects of rules, or unnecessary stringency, not required to achieve environmental or other regulatory objectives;
- Overlap and duplication between permitting processes and agencies; and
- Overly strict or punitive interpretations of guidance, policies or regulations that are often counter to a pro-growth interpretation.

Table 1 provides some examples of these issues:

[8] Responses to the RFI are collected under Docket ID DOC-2017-0001, at www.regulations.gov. Department of Commerce officials also attended a listening session organized by the National Association of Manufacturers (NAM) during which trade association representatives highlighted multiple regulatory and permitting issues. NAM, individual companies and trade associations later submitted comments detailing these issues to the public docket. Upon request, Department of Commerce officials also agreed to meet with company or trade association representatives that had submitted comments to the docket.

Table 1. Examples of Key Issues that Were Identified by Respondents

Category	Problem	Examples from RFI Responses
Inadequate Rule Design	A regulation is written or implemented with a lack of "on the ground" knowledge about how the regulated industry operates,[9] is economically or technologically infeasible, or is based on unrealistic data or assumptions	National Ambient Air Quality Standards (NAAQS) — unrealistic assumptions on background levels; Crystalline Silica Exposure Standard
	There is a lack of clarity around the requirements needed to comply with the regulation	Clean Water Act (CWA) — Definition of Waters of the United States
	The regulation is inflexible or too prescriptive; overly strict interpretations of policy and guidance	New Source Review (NSR) Permitting Process — inflexibility in allowing for aggregation of emissions within a plant
	Overlap or duplication of rules	New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) — overlap
	A better regulatory approach exists to achieve the objectives or the approach actually undermines key regulatory objectives	Resource Conservation and Recovery Act (RCRA) — inappropriate classification of certain waste streams as hazardous, which has perverse effect of discouraging recycling of this waste
	The regulation is outdated	Leak Detection and Repair Rules — outdated monitoring technology options
	Regulatory over-reach — goes beyond statute or rulemaking	New Source Performance Standards (NSPS) — enforcement beyond rules
	Complex, onerous, inefficient and lengthy processes, particularly permitting processes	New Source Review (NSR) Permitting Process
	Uncertainty, particularly permitting processes	Section 404 Wetlands Permitting Process (wide variation in duration)

Cumbersome Processes — Particularly Onerous Permitting Processes	Overlap, duplication or poor coordination between agencies, rules or permits	Title V permitting decisions can be a basis for "re-litigating" decisions already made under NSR pre-construction permitting processes
	Inconsistency, among agencies or between federal and state regulatory authorities, in application or enforcement of rules	CAA permits — EPA often intervenes in state decisions

Selection of Priority Specific Regulatory and Permitting Issues

The selection of priority regulatory and permitting issues in this section was based on the following criteria:

- The volume of responses citing a particular issue (see Table 2 below).
- The number of in-depth or broad scope responses that discussed the issue.
- Comments in the responses that highlighted an issue as of particular importance in terms of regulatory burden or estimated costs; for example, NSR/PSD under the Clean Air Act was often singled out as the most significant regulatory and permitting burden, and the ozone NAAQS standard and crystalline silica exposure standard were both highlighted as resulting in very high costs.
- Issues that were discussed in sufficient detail to identify the nature of the burden and point toward potential solutions and actionable recommendations.[10]
- Some issues were included (or considered) because they have been longstanding challenges.

[9] In response* to the following question: "The most challenging regulations to comply with are due to ____, the statement that most commonly represented the experience of manufacturers surveyed by NAM (41.7% of responses) was "regulatory agencies writing a final rule absent an adequate understanding of my business and my compliance challenges." (National Association of Manufacturers, "Holding US Back: Regulation of the U.S. Manufacturing Sector.").

[10] As an example, though there were numerous concerns expressed about recent changes to the Toxic Substances Control Act (TSCA), resulting from the Lautenberg Chemical Safety Act, the responses did not coalesce around a specific set of issues or recommendations.

Table 2. Most Frequently Cited Regulatory & Permitting Issues that Impact Manufacturing			
	Federal agency	**Issue area**	**# Commenters**
1	EPA	Clean Water Act (CWA): Wetlands Permits and Waters of The United States (WOTUS)	42
2	EPA	Clean Air Act (CAA): National Emissions Standards for Hazardous Air Pollutants (NESHAP) and New Source Performance Standards (NSPS)	41
3	EPA	CAA: New Source Review and Prevention of Significant Deterioration Permits (NSR/PSD)	40
4	EPA	CWA: National Pollutant Discharge Elimination System (NPDES) Permits	31
5	EPA	CAA: Greenhouse Gas Requirements	29
6	EPA	CAA: National Ambient Air Quality Standards (NAAQS) (general)	28
7	EPA	Resource Conservation and Recovery Act (RCRA)	18
8	EPA	Risk Management Programs and Reduced Risk and Tech Review	19
9	EPA	Toxic Substances Control Act (TSCA)	18
10	Department of Labor (DOL)	Improve Tracking of Workforce Injuries and Illnesses	14
11	Departments of Interior and Commerce (DOI and DOC)	Endangered Species Act (ESA)	13
12	Securities and Exchange Commission (SEC)	Conflict Minerals Rule (Dodd-Frank)	12
13	EPA and others	National Environmental Policy Act (NEPA)	11

14	EPA	Regional Haze Requirements	10
15	DOL	Crystalline Silica Exposure	10
16	DOL	Overtime Rule	9
17	EPA	Comprehensive Environmental Response, Compensation & Liability Act (CERCLA)	9
18	EPA	Spill Prevention, Controls, and Countermeasures	9
19	Equal Employment Opportunity Commission (EEOC)	EEO-1 Form	7
20	Department of Health and Human Services (HHS)	Food Safety Modernization Act (FSMA)	5

Priority Regulatory and Permitting Issues

This report focuses on regulatory and permitting issues that directly affect the construction, operation or expansion of manufacturing plants. While some of these regulatory issues primarily affect the manufacturing sector, others affect businesses across multiple sectors. Several issues are highlighted due to their indirect impacts on manufacturing, a perceived high level of adverse impact on economic growth, and other factors. The following are priority regulatory and permitting issues identified by respondents to the RFI. Refer to the appendix for a list of respondents that are referenced in this report.

Clean Water Act: Wetland Permits and Waters of the United States (WOTUS) Rule

As part of the Clean Water Act (CWA), the Environmental Protection Agency (EPA) regulates discharges of pollutants into "waters of the United States." In 2015, EPA promulgated the Clean Water Rule[11], which was perceived by many respondents to have expanded the definition of waters of the United States — or at least added ambiguity to its definition — in ways that extend federal authority beyond the traditional limits. Different sources describe the expanded scope in different ways. For example, NAM states that it "extend(s) federal jurisdiction of CWA programs well beyond traditional navigable waters to ephemeral tributaries, flood plains, adjacent features and vaguely defined 'other waters'... For manufacturers, the

[11] 80 Fed. Reg. 37054 (June 29, 2015).

ED_001598_00010057

uncertainty of whether a pond, ditch or other low-lying or wet area near their property is now subject to federal CWA permitting requirements, can introduce new upfront costs, project delays and threats of litigation." (146-NAM) The U.S. Chamber of Commerce (CoC) states that it includes "ditches, canals, and even land that is dry most of the year, as long as water runs over that land sometime on its way to interstate waters." Many respondents expressed the view that the definition of "waters of the United States" set in the rule is too broad and that a narrower definition would be appropriate. (6-NFIB, 146-NAM)

The rule was stayed by the 6th Circuit Court of Appeals on October 9, 2015.[12] On February 28, 2017, the President issued Executive Order 13778 directing the EPA and the Army Corps of Engineers (Corps or USACE) to review the WOTUS rule. On March 6, 2017, the Corps and EPA published a notice announcing their intent to review the rule and seek to provide greater clarity concerning the definition of "waters of the United States."[13] On July 27, 2017, the EPA and the USACE published a proposed rulemaking to repeal the 2015 Clean Water Rule and reinstate the regulations in place prior to its issuance.[14] As indicated in the proposed withdrawal, the agencies are implementing EO 13778 in two steps to provide as much certainty as possible as quickly as possible to the regulated community and the public during the development of the ultimate replacement rule. In Step 1, the agencies are taking action to maintain the legal status quo of the rule in the Code of Federal Regulations, by recodifying the regulation that was in place prior to issuance of the 2015 Clean Water Rule. Currently, Step 1 is being implemented under the U.S. Court of Appeals for the Sixth Circuit's stay of the rule. In Step 2, the agencies plan to propose a new definition that would replace the approach in the 2015 Clean Water Rule with one that reflects the principles in EO 13778.

Clean Air Act: National Emissions Standards for Hazardous Air Pollutants and New Source Performance Standards

The National Emissions Standards for Hazardous Air Pollutants (NESHAP) of the Clean Air Act (CAA) limits emissions levels for specific pollutants from a variety of specific sources and manufacturing processes. The Air Permitting Forum (APF) provides a summary of how NESHAPs work:

> The CAA Section 112 program covers the regulation of hazardous air pollutants (a defined list) for various source categories. Initially, these NESHAPs were established based on a review of currently employed air pollution control technology applied to existing and new sources (referred to as Maximum Achievable Control Technology, or MACT). Then, after eight years, the statute requires EPA to conduct residual risk and technology reviews. EPA assesses the risk remaining after application of MACT controls and determines if it is acceptable. If not acceptable, further controls must be applied. EPA is also required [every eight years] to evaluate if advances in control

[12] Ohio v. United States Army Corps of Engineers (In re EPA & DOD Final Rule), 803 F.3d 804 (6th Cir. Oct. 9, 2015).

[13] 82 FR 12532 (March 6, 2017).

[14] 82 FR 34899 (July 27, 2017).

technologies have occurred since the MACT and to determine if their application to the source category is appropriate. (170-APF).

Because the standards may apply to sources that are subject to another set of rules (the New Source Performance Standards (NSPS), discussed below) a number of respondents have suggested there are opportunities to consolidate and rationalize the requirements of these two sets of regulations. In addition, there are also a series of perceived "unnecessary burdens" specifically related to NESHAPs.

A number of respondents expressed concern about the residual risk and technology reviews (RTRs) as leading to unnecessary additional requirements with no (or limited) environmental benefit. For example, NAM provided the following illustrative example for a sandblasting operation:

> For one manufacturer, this means having a dedicated employee climb on the roof of eight different manufacturing plants at the required interval (daily/weekly/monthly/quarterly) to do multiple 15-minute observations on each roof, and perform visual observations of the on-site sandblasting booth at the required interval, only to document that zero visible emissions occurred at every observed location during every monitoring event. Since 2011, this manufacturer has made over 700 visual observations consuming over 1,000 man-hours to comply with this regulation, despite having not once observed a "visible emission" at any of the plants. (146-NAM)

Another example provided was secondary aluminum production, illustrating how regulations that emerged from an RTR led to rules that did not reflect real world operating conditions. This rule required "hooding" for new "round top furnaces," which was impractical because they were incongruent with the charging method for this type of furnace which requires an overhead crane and lifting of the lid. (101-AA)

One set of Maximum Achievable Control Technology (MACT) rulemakings for a particular source category (MACT for industrial and commercial boilers and process heaters) has received particular attention in recent literature, and in the RFI responses. The rulemakings for this source category have occurred over the last 20 years, and are being reviewed based on a 2016 court decision, which is causing the EPA to consider additional "best performing boilers."[15] The length and complexity of the rulemaking process has created uncertainty for manufacturers.[16] In addition, specific requirements were identified by some respondents as burdensome, such as in the case of steel facilities:

> The requirement to test/tune/test each burner of each applicable source is a burdensome exercise. At many steel making facilities there are multiple finishing lines with indirect heating furnaces that are comprised of hundreds of natural gas fired burners each below 5 MMBTU/hour. These units are considered cumulatively under the Boiler MACT and are therefore required to have annual tune-ups per 40 CFR. § 63.7515(d). The annual tune-ups require excessive line outages and man

[15] See, https://www.epa.gov/boilers.

[16] Paul R. Noe, "Smarter Regulation for the American Manufacturing Economy," American Forest and Paper Association, September 14, 2016.

hours. The annual requirement for testing and tuning of the many small burners can range up to $100,000 for a company with the time, equipment and proper skills to conduct the tuning. For natural gas sources with burner sizes less than a certain threshold, reducing the frequency of these tune-ups to every five years would significantly reduce the cost burden. (92-AISI)

Another MACT-related issue raised by respondents relates to the "once-in-always-in" policy.[17]

The Clean Air Act defines emissions limits for specific types of stationary sources. These New Source Performance Standards (NSPS) are specific to approximately 90 different industries/manufacturing processes. NSPS applies to "new, modified and reconstructed" facilities. As an example, there is a NSPS standard for volatile organic compounds (VOCs) for surface coating processes for large appliances.[18]

For NSPS, the specific regulatory burdens cited often were not the rules themselves, but the potential for overlap and redundancy with related rules, such as National Emissions Standards for Hazardous Air Pollutants (NESHAPS, discussed above). NAM and IECA specifically suggest there are opportunities to rationalize the NSPS and NESHAP requirements, reporting and recordkeeping. (146-NAM, 89-IECA) Both sets of rules limit emissions from specific manufacturing processes, suggesting that there may be opportunities to integrate the two standards. NAM gives a specific example of the opportunity to rationalize 8 different regulations for different coatings processes. (146-NAM)

More frequently mentioned were examples of enforcement reaching beyond explicit NSPS standards. (89-IECA, 92-AISI, 112-SMA) AISI gives the example of the EPA using enforcement actions to limit fugitive emissions of particulate matter in steel making facilities that are not explicitly delineated in the NSPS. (92-AISI)

Clean Air Act: New Source Review and Prevention of Significant Deterioration Permits

The New Source Review (NSR) permitting program under the Clean Air Act was cited in many of the RFI responses as one of the most important opportunities to streamline permitting processes for manufacturers. An NSR "preconstruction" permit is required for new industrial facilities (and other new "major sources") or for "major modifications" of existing facilities.[19] The objectives of the program are to protect air quality by limiting increases in emissions and by ensuring that "advances in pollution control technology occur" as part of industrial expansion. The NSR program has different requirements depending on whether facilities are in "attainment" areas that are meeting National Ambient Air Quality Standards (NAAQS) for six specific "criteria" pollutants, or whether they are in non-attainment areas. Permits that are required to be obtained in

[17] Under the "once-in-always-in" policy, EPA requires that a major source, subject to the MACT technology standard, remains subject to that standard even if "the facility undertakes pollution prevention or installs control devices to reduce emissions below the major source applicability thresholds." (170-APF). That means a company is subject to a higher standard than is "justified' by their current emissions levels. Perversely, this creates a disincentive for companies to reduce emissions. (170-APF).

[18] New EPA NSPS for industrial surface coating for large appliances.

[19] For more information on NSR permitting, see www.epa.gov/NSR.

attainment areas are known as Prevention of Significant Deterioration (PSD) permits. Table 3 below outlines the broad requirements for NSR and PSD permits:

Table 3. Requirements for New Source Review and Prevention of Significant Deterioration Permits	
New Source Review (Nonattainment Area)	**Prevention of Significant Deterioration (Attainment Area)**
1. Installation of the Lowest Achievable Emission Rate or LAER ("meaning that the plant must install state-of-the-art pollution controls in order to match or exceed the emission rate achieved by the lowest emitting similar facility in the country") (48-AF)	1. Installation of the Best Available Control Technology or BACT (similar to LAER, but sometimes less stringent, and assessed on a case-by-case basis) (48-AF)
2. Emissions offsets (reductions) from other plants in the same area that yield a net air quality benefit for the region	2. An air impact analysis or modeling that demonstrates that the increase in emissions: 1) "will not result in changes in ambient air quality that would cause the area to exceed NAAQS for any pollutant, and 2) even if projected emissions will not violate NAAQS, they will not result in an increase in ambient concentrations of any pollutant that exceeds the allowable PSD 'increments' set by the CAA"
3. Alternative Sites Analysis	3. An additional impacts analysis (which "assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant" from the source)[20]
4. Opportunities for public comment	4. Opportunities for public comment
Sources: www.epa.gov/nsr, 48-AF, 92-AISI, 136-AFPM, EPA, Webinar Slides: Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a GHG Significant Emission Rate (SER): Proposed Rule, September 20, 2016[21]	

[20] For more information on NSR permitting, see www.epa.gov/NSR.

[21] 81 FR 68110 (October 3, 2016).

The NSR/PSD permitting processes are perceived by RFI respondents to be unnecessarily cumbersome and lengthy. The time required to obtain a preconstruction permit, once an application is received, can range from 9 months to as much as 2-3 years. (48-AF, 170-APF) This duration does not include the months (or even years) required to prepare the application, nor does it include potential delays that can lengthen the process or make its timing uncertain, such as the need to revise air quality modeling when a NAAQS standard is changed, or the possibility of an appeal or review by the EPA of a state decision to issue a permit. (170-APF, 10-PCBI, 89-IECA)

Respondents indicated the costs to prepare an application and construct air quality and dispersion models are significant, not to mention the costs of emissions offsets and what is sometimes perceived as "over-investment" in pollution control equipment due to the conservative assumptions built into these models. The result is that manufacturers avoid making investments to modernize facilities, improve processes or increase quality for fear of triggering an NSR/PSD requirement. (146-NAM, 10-PCBI)

A number of recommendations have been put forward to address various issues that arise under NSR/PSD:

- Turnaround Time. One proposal is to enforce reasonable turnaround times. (48-AF) According to a recent paper,[22] under the CAA, "EPA and other permitting agencies are required to either grant or deny an NSR permit within one year of receiving a permit application, but there is no practical way to enforce this deadline." In addition to setting firm deadlines, other suggestions include:
    - Limiting challenges or appeals, including limiting the ability of the EPA to review or reject the decision of a state permitting authority. (89-IECA, 170-APF, 10-PCBI)
    - Allowing some construction activities to commence that do not generate emissions, prior to receiving a permit. (146-NAM)
- Aggregation. There are also a set of rules regarding the "aggregation" of emissions (within a facility, over time within a facility, or across locations) that affect whether the need for a NSR/PSD permit process is triggered. A number of respondents made suggestions or encouraged approaches that allow flexibility for sources to aggregate emissions and thus demonstrate that total emissions are not increasing sufficiently to trigger an NSR/PSD process. (In some cases this would involve clarifying rules or "solidifying" past reforms already proposed.) These recommendations include:
    - Plant-Wide Applicability Limitations (PALs) — EPA could promote and facilitate "Plant-Wide Applicability Limitations (basically emissions limits that apply facility-wide) through a

[22] Art Fraas, John D. Graham, and Jeff Holmstead, "EPA's New Source Review Program: Time for Reform? " Environmental Law Reporter, 1-2017.

permitting process, allowing such a facility to change, modify and upgrade equipment and operations and add new equipment without triggering major modification NSR review, provided the changes do not result in exceeding the established PAL emissions limits." (92-AISI quote, also 170-APF)

- Units that precede or follow the unit being modified should not be considered as part of emissions increases that might trigger NSR. (170-APF, 136-AFPM)

- Clarifying the rules around definition of a project, and whether separate activities can be grouped together into a project for purposes of triggering NSR/PSD. (170-APF, 136-AFPM, 146-NAM)

- Rules that Avoid Triggering NSR. There were also recommendations relating to the rules that trigger NSR, such as:

  - Revisiting and expanding the definition of activities that are defined as "routine maintenance, repair and replacement," which are exempted from NSR/PSD requirements. (92-AISI, 170-APF)

  - Using actual emission increases versus theoretical or maximum "potential to emit" in calculations. (10-PCBI, 136-AFPM)

- Modeling. Numerous respondents identified the need to avoid delays and re-work in the application and air quality modeling process. (Note that a more general discussion of NAAQS and modeling is found in the section below.) Recommendations include:

  - Introducing guidance on modeling at the same time as NAAQS standards are revised, so there is clarity on modeling required as part of an NSR application. (92-AISI, 48-AF)

  - "Grandfathering" NSR applications that were submitted, but not yet approved, prior to a change to NAAQS standards, so companies do not have to revise the applications to conform to the new standards. (92-AISI, 48-AF)

- BACT and LAER determinations. Several respondents offered suggestions about how to improve the process of determining the required pollution control technology, which is perceived to be onerous and susceptible to delays:

  - PSD BACT determination should be based on proven, domestic technology that is in the same "industrial category" as the applicant and was in existence when the application was submitted (92-AISI, 10-PCBI) and should consider alternatives to the "top down" BACT analysis process. (170-APF)

- Emissions Credits or Offsets. Respondents also raised concerns that there can be challenges in obtaining emissions credits in non-attainment areas, and when they are available they can be very expensive. In one example, a relatively small new facility in Houston (emitting more than 100 tpy of Volatile Organic Compounds or NO_2) may need to spend between $32 million and $52 million for emissions offsets. (48-AF) Recommendations by respondents include:
    - Increased flexibility for buying offsets from outside the local areas where a new facility is being established. (48-AF)
    - Emission fees versus credits (which would require a statutory change). (48-AF) A recent paper on EPA's NSR program stated: "We propose a narrow statutory reform that could address these issues while still obtaining most or perhaps even more of the environmental benefits of the current program: allow permit applicants to pay emissions fees in lieu of meeting the current offset requirements, and require the state or local environmental agency to use these fees to pay for or subsidize emissions reductions that the agency believes will do the most good in terms of reducing environmental risks."[23] (48-AF)

The other major permit required by the CAA (beyond NSR/PSD) is the Title V operating permit for major (and some minor) sources, which incorporates all of the federal and state air pollution control requirements in one place. (170-APF). The operating permit must be renewed every 5 years.

Industry respondents suggested that it has become costly to obtain, maintain and renew operating permits. (170-APF) AISI reported "varied timelines for completing the Title V review and approval process, depending on the state regulatory agency and EPA Regional Office, taking up to three years to receive the final permit and costs of several million dollars for each operating permit needed." (92-AISI) And according to the Air Permitting Forum, "the cost of the program today is far more than was ever anticipated. . .given the enormous costs of the program, it is incumbent on the government to take whatever steps it can to streamline permitting and minimize costs." (170-APF)

Concerns were also raised that even when an NSR/PSD preconstruction permit already has been obtained, the Title V permit process provides another opportunity for NGOs or others to mount a legal challenge "on the same grounds that have already been adjudicated." (170-APF) Moreover, "Title V petitions often sit in a long queue at EPA, and then can end up back in court—duplicating costs for industry to defend its expansive and long-evaluated permits." (170-APF)

A related problem is the concern that the operating permit, which is intended to consolidate various regulatory requirements, is being used (e.g., by states) to add additional requirements or impede flexibility in meeting other requirements imposed by the CAA (e.g., such as using the permit language to limit the options for an appliance surface coating operation in meeting MACT standards for hazardous air pollutants

[23] Art Fraas, John D. Graham, and Jeff Holmstead, "EPA's New Source Review Program: Time for Reform? " Environmental Law Reporter, 1-2017.

(HAPs), which otherwise would be able to meet requirements by changing materials or adopting controls). (170-APF)

In addition to an overall desire to streamline the approval process, specific recommendations include: eliminating the ability of EPA or other stakeholders to "re-litigate" preconstruction NSR/PSD permit decisions during the Title V permitting process (170-APF); extending the term of the permit from 5 to 10 years (170-APF); and citing other requirements in the permit rather than recreating or summarizing those requirements in their entirety in the permit itself. (170-APF)

Historically, the CAA has exempted Start-up, Shutdown and Malfunctions (SSM) periods from the emissions restrictions that apply under normal operating periods. However, in response to recent court decisions, the EPA has reversed course, and proposed new rules (in 2016) to eliminate these exemptions and eliminate the "affirmative defense" provision for emergencies. Numerous industry respondents have urged that the SSM exemptions be restored (89-IECA, 170-APF, 92-AISI):

> "Unless EPA acts quickly, every manufacturing company in the country operating under a Title V air permit could be subjected to unnecessary citizen suits and potential civil penalties as they shut down and start-up their equipment to conduct maintenance activities and other planned and unplanned outages." (89-IECA)

It has also been suggested that other alternative approaches could be explored, such as developing a more "judicially sound affirmative defense concept" or "re-promulgating technology based emissions standards sufficient to cover emissions associated with SSM events." (101-AA)

Clean Water Act: National Pollutant Discharge Elimination System Permits

Section 402 of the CWA — known as a National Pollutant Discharge Elimination System (NPDES) — requires a permit to discharge pollutants from a "point source" into "waters of the United States." "The permit will contain limits on what you can discharge, monitoring and reporting requirements, and other provisions to ensure that the discharge does not hurt water quality or people's health."[24] An NPDES Storm-water program also requires a permit for some storm-water discharges, which are not considered point sources. Also under the CWA, a section 404 permit may be required for the discharge of dredge or fill material into "waters of the United States." Section 404 is managed by the EPA and US Army Corps of Engineers.

A primary concern expressed by RFI respondents was the complexity of these permitting processes, and the time required to obtain a permit. According to AISI, "[t]he 404 permitting process is currently one of the most ill-defined processes for a regulated party to understand and thus to predict permit timelines." (92-AISI). Respondents reported that Section 404 permits can take 1-4 years or more to obtain and NPDES permits require 6 months or more. (92-AISI) In reference to wetlands (Section 404) permitting, SMA stated

[24] See www.epa.gov/npdes for more information on the Section 404 permitting process.

that "USACE [US Army Corps of Engineers] permitting processes are slow, antiquated and expensive." (112-SMA) And regarding NPDES, the Aluminum Association's assessment is that the "antiquated permitting timeline embedded in these regulations costs business money and lost opportunities for growth." (101-AA)

Some of this long permitting cycle is driven by the complexity of the law and the permitting process, which requires permits for industrial discharges from point sources, often based on effluent guidelines for specific industrial processes (which are sometimes complicated by Total Maximum Daily Load limits on the amount of "pollutant a waterbody can receive"); a separate permit process for discharges that go into publicly owned treatment works (POTWs), for storm water, and for wetlands; a set of requirements for cooling intake water; and significant operational proscriptions and recordkeeping/reporting. (See www.epa.gov/npdes and 92-AISI; 112-SMA; 136-AFPM; 101-AA)

The recommendations by respondents generally revolve around streamlining the process, eliminating duplicative requirements, making the steps to obtain a permit more defined (with fewer open-ended steps), and shortening the process timeline. (92-AISI, 101-AA, 76-Boeing)

Clean Air Act: Greenhouse Gas Requirements

Greenhouse Gas (GHG) emissions are now regulated under the CAA, using PSD and Title V permitting processes.[25] The objective was to introduce "GHG emissions thresholds that define when permits under these permitting programs were required" for new or modified sources.[26] Litigation has caused a revision of the rules, which is still in progress.[27] The primary result of the decision was that the EPA "may not treat GHGs as an air pollutant for the specific purpose of determining whether a source is required to obtain a PSD or Title V permit."[28] In other words, a "BACT analysis for GHGs" is only required in cases "where another air pollutant triggers a review" and the requirement to obtain a PSD or Title V permit. (136-AFPM) A revised rule has been proposed, and final comments were due in December 2016.

Nevertheless, for major sources that require Title V and PSD permits for another pollutant, EPA can apply BACT requirements to GHGs above a specific threshold, which has been proposed at 75,000 tons per year (tpy) CO_2e Significant Emission Rate (SER). The court decision referred to above also requires a justification for this threshold level. There is concern among a number of RFI respondents that this threshold level of GHG emissions is too low, and that the benefit in terms of a reduction in GHG emissions

[25] The EPA's original Greenhouse Gas Regulations consisted of the "Endangerment Finding" (74 FR 66523 (2009)), the "Triggering Rule" (75 FR 75004 (2010)), the "Tailpipe Rule" (75 FR 25324 (2010)), and the "Tailoring Rule" (75 FR 31514 (2010)).

[26] EPA "Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a GHG Significant Emission Rate (SER): Proposed Rule," Webinar, Sept. 20, 2016.

[27] *Utility Air Regulatory Group v. EPA; Coalition for Responsible Regulation v. EPA*.

[28] EPA "Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a GHG Significant Emission Rate (SER): Proposed Rule," Webinar, Sept. 20, 2016.

would not justify the additional regulatory burden. (89-IECA, 136-AFPM) Respondents, therefore, recommend the EPA prioritize an expedited and judicious review of SER thresholds for GHGs.

Clean Air Act: National Ambient Air Quality Standards

The EPA establishes National Ambient Air Quality Standards (NAAQS) for six "criteria" air pollutants (carbon monoxide, ozone, lead, nitrogen dioxide, particulate matter, and sulfur dioxide). Regions are designated as "attainment" areas (which meet the NAAQS standards), non-attainment regions, or unclassified. Non-attainment regions are considerably more restricted in allowable emissions, thus limiting the potential for new manufacturing plants and plant expansions. NAAQS standards have been continually ratcheted downward; the 2015 ozone regulation established a standard of 70 parts per billion (ppb), which revised a 2008 standard of 75 ppb that has not yet been fully implemented.[29] (89-IECA, 136-AFPM) At 70 ppb, respondents raised concerns that the level is approaching "background" levels of ozone. (48-AF,146-NAM, 112-SMA) Respondents also raised concerns that the pace at which the standard has been revised has not allowed sufficient time for implementation, and is further complicated by measurement and (again) air quality modeling issues — in particular accounting for ozone transported from international sources. (112-SMA,107-COC) As noted in a recent paper:

> Recent research has found that stratospheric intrusions and long-range transport—particularly in western states—have resulted in daily maximum eight-hour ozone levels of 70 ppb or more. With the ozone NAAQS at or below background, sources will find it impossible to show that they will not "contribute to" a violation of the standard. (48-AF)

Some observers recommended that implementation be delayed.[30]

Because of this increasingly restrictive standard, respondents specifically raised concerns that the current NAAQS standard for ozone is not practicable to implement, will shift numerous areas into a non-attainment designation, and will severely restrict the ability of manufacturing companies to establish new facilities or expand existing facilities in those regions. (136-AFPM, 112-SMA, 89-IECA)

Because of this narrow margin, numerous respondents identified the need for EPA to improve air quality and dispersion models. For example, one respondent stated:

> In conducting an analysis for the PSD program, facilities must use EPA-approved models to demonstrate that a project will not cause a violation of a NAAQS standard. The models' overly conservative algorithms and assumptions, however, can create a modeling result that rarely represents and often significantly overestimates monitored concentrations around the facility.

[29] A NAM-NERA 2014 report assessed the impact of a more stringent 60ppb standard that was contemplated at the time, and the analysis suggested the economic impact would be enormous: "...the potential emissions control costs would reduce U.S. Gross Domestic Product (GDP) by $270 billion per year on average over the period from 2017 through 2040... The potential labor market impacts represent an average annual loss of 2.9 million job-equivalents." (NERA Economic Consulting, "Assessing Economic Impacts of a Stricter National Ambient Air Quality Standard for Ozone," Prepared for NAM, July 2014). In contrast, the EPA estimated costs of $560M for what appears to be the final rule of 70ppb. (OMB, "2016 Draft Report") .

[30] 146-NAM, Letter to National Economic Council, regarding regulations of concern, Business Roundtable, February 22, 2017.

> Reliance on modeling that over-predicts ambient concentrations can result in additional unwarranted costs by causing facilities to install beyond-BACT pollution control equipment, even though the assumptions used in the models and the predicted concentrations are not representative of real-world conditions. (170-APF)

Some of the specific suggestions to improve the approach involved re-examining assumptions about background concentration levels, the treatment of fugitive emissions, use of actual emissions rather than theoretical or maximum operating rates, employing probabilistic models, and reconsidering inappropriate "ambient air receptor" locations where individuals will not generally be exposed to emissions. (89-IECA, 92-AISI, 170-APF, 112-SMA, 136-AFPM)

Others recommended that changing the timetable for mandatory NAAQS reviews from every five years to every ten years would allow more time to meet the previous standard. (107-COC, 136-AFPM, 10 PA) In addition, the CoC notes that these "five-year deadlines are regularly exceeded by the EPA and inevitably result in 'sue-and-settle' agreements." Five-year review cycles have the potential to result in over regulation and constant changes requiring capital outlays from the private sector. Implementing the respondent's recommendation would require Congress to update the NAAQS review schedule to reflect a 10-year cycle. This update would allow for complete realization of environmental improvements, and would bring greater certainty to regulated operators.

Another frequent recommendation raised by respondents is to re-examine and clarify how to account for international and long-range transport of ozone, and for exceptional events. For example, the EPA has a policy which would allow it to "disregard exceedances of a NAAQS caused by certain types of exceptional events," such as stratospheric intrusions. However, it was suggested that in practice it is difficult to obtain EPA "recognition" of exceptional events in an NSR application. (48-AF) In light of this phenomenon, where meteorological conditions play a role in transporting extra-jurisdictional emissions, EPA should exclude those emissions from regulatory consideration, classifying them as "exceptional events." Respondents recommend that EPA employ all tools available to discount for "background" conditions and allow the maximum degree of flexibility afforded by statute.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) is a set of laws, regulations and policies that govern management and cleanup of solid, liquid, and gaseous hazardous waste.[31] Manufacturers are affected by RCRA because of the generation of waste streams in their factories. An issue identified by several respondents is the inappropriate classification of certain waste streams as hazardous, which impose burdensome additional requirements, and have the effect of discouraging recycling, reuse or reclamation. (146-NAM) For example, AISI has proposed that baghouse dust from electric arc furnaces (EAFs) be delisted as hazardous, which would open up additional recycling or reuse opportunities (without always employing an RCRA-permitted recycling operator). SMA similarly suggested that by-products from EAFs

[31] For more information, see https://www.epa.gov/rcra.

are sometimes classified as hazardous, resulting in more complex and burdensome management requirements, which again undermine the goal of recycling. (112-SMA) In 2015, EPA has added a restrictive criterion for "legitimacy" which results in unnecessary treatment and disposal of material that could be reused or recycled for other purposes.[32] Respondents recommend updating the rule to allow for more beneficial uses of substances where reuse or recycling can be justified by industry. Additionally, another respondent proposed an aggressive approach to delisting waste as "hazardous," where appropriate, which would reduce regulatory burden. (76-Boeing)

On November 28, 2016, the EPA published the Hazardous Waste Generators Improvement Rule.[33] According to 89-IECA it "causes waste generators who violate even one 'Condition for Exemption' from permitting to be treated as [full-fledged] waste treatment, storage, and disposal facilities requiring RCRA permits. Violation of a single minor condition can, therefore, mean that an otherwise exempt facility must obtain a RCRA permit and can be cited for violations of numerous regulations and permit conditions" (136-AFPM) or be subject to more onerous regulations. (89-IECA) It is recommended the rule be revised to allow some leeway on conditions of exemption and associated violations.

Risk Management Programs

Section 112(r) of the Clean Air Act addresses the prevention of accidental releases of hazardous substances. Respondents raised concerns that EPA's recently issued Risk Management Plan (RMP) rule (40 CFR, Part 68, finalized in 2017), which would add unnecessary or unreasonable additional burden for affected facilities.

For example, there is significant concern about duplication and conflicting requirements under the rule with Occupational Safety and Health Administration (OSHA) Process Safety Management standard. (136-AFPM, 43-Mosaic, 133-PIA) In addition, several elements of the new requirements were perceived as unnecessary or inflexible. One such area is the requirement for third party audits in certain circumstances (such as chemical release or instance of non-compliance). (136-AFPM, 109-Valero) One respondent suggested appropriately trained internal staff could perform audits, and also suggested the qualifications for third party auditors outlined in the regulations were too restrictive. (158-CKRC) An additional requirement highlighted was the need for a "resource-intensive inherently safer technology analysis" that according to one respondent "provides little value after a facility is already built" (136-AFPM), and which another respondent said will "increase compliance costs without improving safety." (109-Valero) Finally, several respondents expressed concern about reporting requirements that would release sensitive information that could be used for lawsuits or potentially even terrorist attacks. (146-NAM, 109-Valero, 136-AFPM) Legal action has been taken seeking reconsideration of the rule. (136-AFPM) On March 13, 2017, the EPA convened a proceeding to reconsider RMP Rule.[34] On June 14, 2017, the EPA published a final rule to

[32] 80 Fed. Reg. 1693-1814 (Jan. 13, 2015), revising 40 CFR. Parts 260 & 261.

[33] 81 FR 85732 (November 28, 2016).
[34] 82 Fed. Reg. 13968 (March 16, 2017).

further delay the effective date of the RMP Rule for 20 months until February 19, 2019, to allow adequate time for the reconsideration.[35]

Toxic Substances Control Act

The Toxic Substances Control Act of 1976 (TSCA) provides EPA with authority to require reporting, record-keeping and testing requirements, and to impose restrictions relating to chemical substances and/or mixtures. Certain substances are generally excluded from TSCA, including, among others, food, drugs, cosmetics and pesticides. The types of chemicals regulated by TSCA fall into existing (chemicals on the TSCA Inventory) and new, which is an important distinction as TSCA regulates each category differently. For new chemicals, manufacturers must submit a pre-manufacturing notification to EPA prior to manufacturing or importing new chemicals for commerce. TSCA also specifically addresses the production, importation, use, and disposal of specific chemicals including polychlorinated biphenyls (PCBs), asbestos, radon and lead-based paint. The most common issue with TSCA expressed by the respondents was the restrictions imposed on manufacturing and use of chemicals that have the potential to drastically and unnecessarily impact profit, productivity, competition and jobs. (37-ILMA, 39-IPC, 51-NSSGA, 56-CPA, 101-AA, 115-HSIA, 116-NAFO, 141-ACC, 151-PESA, 155-PMPA) It should be noted, however, that on June 22, 2016, the Frank R. Lautenberg Chemical Safety for the 21st Century Act, which amended TSCA, was signed into law, addressing some of the shortcomings in the original law and adding a mandatory duty to evaluate chemicals and a new risk-based safety standard.

Improve Tracking of Workforce Injuries and Illnesses

In May 2016, the Occupational Safety and Health Administration (OSHA) published its final rule to "Improve Tracking of Workplace Injuries and Illnesses."[36] However, manufacturers are concerned that this rule requires them to submit electronic records of workplace injuries and illnesses, which OSHA is planning to post on a public website. (92-AISI, 146-NAM, 107-COC) RFI respondents have voiced two objections to making the data publicly available: 1) the information may be used by union organizing campaigns, or as the basis of litigation on safety issues; 2) privacy concerns exist, as there may be identifying information included in the reporting that could expose sensitive, proprietary information. (92-AISI, 146-NAM, 107-COC) Also, there are requirements for establishing a reasonable system for workers to report injury or illness, along with provisions that prevent employers from retaliating against whistleblowers or in other ways discouraging injury or illness reporting.

Guidance issued on how to comply with the rules included language that suggested some safety performance incentives and drug testing programs might be construed as in violation of the rule, as they might deter reporting (to improve safety performance measures or to avoid post-accident drug testing).

[35] 82 Fed. Reg. 27133 (June 14, 2017).
[36] 81 FR 29623 (May 12, 2016).

(107-COC; 92-AISI; 39-IPC) Respondents would like the plan to post safety data online to be reconsidered, and to clarify the guidance so that it does not undermine safety incentive and drug testing programs.

Endangered Species Act

Specific concerns raised relating to the Endangered Species Act (ESA) fall primarily into three categories. First, federal agencies issuing permits must consult with the U.S. Fish and Wildlife Service when construction may affect an endangered or threatened species; this consultation adds considerably to permit time and complexity. (51-NSSGA, 84-Ameren, 114-AGC, 136-AFPM) Second, due to high volume, ESA rules such as the 2016 Critical Habitat Designations, have become "unreasonable." (86-IPAA, 114-AGC, 144-AFPA, 146-NAM, 152-AWC) Finally, concerns were raised that the ESA is being exploited by project opponents as a means of blocking permits. (75-SLMA, 107-COC, 126-API)

Conflict Minerals and Dodd-Frank

Section 1502 of the Dodd-Frank Act[37] mandates that the U.S. Securities and Exchange Commission (SEC) create rules[38] that require public companies that use conflict minerals (tantalum, tin, gold or tungsten) in the manufacture of their products to "undertake 'due diligence' on the source and chain of custody of its conflict minerals and file a Conflict Minerals Report" and publicly disclose this information.[39] The concern is that the mineral may have come from or near the Democratic Republic of the Congo and its use, therefore, is contributing to a humanitarian crisis. A significant issue is that the due diligence requirement is directed back on to suppliers, which are often small to medium sized manufacturers who cannot easily comply with this burden. (53-ACMA, 120-NTMA/PMA, 137-MEMA, 146-NAM) One respondent noted that both the Department of Commerce and the SEC stated they lacked the expertise in this type of back-to-the-mine-of-origin investigation, and given this, asks how small firms can be asked to do these types of investigations. (120-NTMA/PMA)

According to NAM, the "SEC estimates that it will take the average manufacturer 480 hours annually to comply with this regulation."[40] Another association stated, "a large Tier 1 supplier estimated that their expenditures have totaled about $3 million since the annual reporting requirements took effect. These costs include tracking the supply chains and processes of over 7,000 lower tier suppliers, evaluating the minerals tracking efforts of all suppliers, and categorizing the likelihood that a supplier's products contain conflict minerals. Additional costs are incurred because all findings from the company's suppliers must be manually entered into a database and categorized so that the information provided may be utilized by the Tier 1

---

[37] PL 111-203, Dodd-Frank Wall Street Reform and Consumer Protection Act, July 21, 2010.

[38] 17 CFR 240 and 249b.

[39] SEC Fact Sheet, https://www.sec.gov/opa/Article/2012-2012-163htm---related-materials.html.

[40] National Association of Manufacturers, "Holding US Back: Regulation of the U.S. Manufacturing Sector," prepared by Pareto Policy Solutions, LLC.

supplier in preparing filings."(137-MEMA) Many respondents suggested that the rule be suspended. (14-Chromaflo, 39-IPC, 53-ACMA, 71-Whirlpool, 107-COC, 120-NTMA/PMA, 137-MEMA; 146-NAM)

A second SEC issue was the CEO pay ratio disclosure provision required by Section 953(b) of the Dodd-Frank Act. This provision calls for public companies to disclose the ratio of employees' median pay to the compensation of a company's chief executive officer. The SEC finalized a rule for this provision in August 2015, and it becomes effective in 2018. NAM notes that this ratio is a "false and overly simplistic" metric of company compensation practices and it is burdensome due to the costs associated with calculating median pay. (146-NAM) The U.S. Chamber echoes those concerns and notes that some municipalities are "enacting a new tax based upon this ratio." (107-COC) NAM asks that the SEC reconsider the rule entirely.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) requires that federal agencies consider significant environmental impacts in their decision-making, and established the President's Council on Environmental Quality (CEQ). Federal law requires permits for many kinds of industrial and commercial activity, and the issuance of such permits often triggers a requirement for NEPA analysis. This process can quickly become extremely lengthy and costly. For example, according to NAM:

> It (the NEPA) is often the largest, costliest, most time-consuming regulatory hurdle that project sponsors, developers, construction managers and engineers face before they can build. Philip Howard's 2015 report, "Two Years, Not Ten Years: Redefining Agency Approvals" explains that public project costs are increased by more [than] $3.7 trillion because of red tape. It is also a common target for abuse, as there are countless ways for federal and state agencies and external actors to throw a wrench in the process and delay completion of the review. The longer the delay, the more likely the developer walks away. Project opponents do not often need a [court] judgment on the merits of NEPA to win; the delay can be enough... A 2014 GAO report made several startling findings with respect to the administration of NEPA. [GAO found that the] Administration had no idea how long a typical NEPA review takes. GAO's best guess was an analysis by the National Association of Environmental Professionals (NAEP), which estimates that the average environmental impact statement (EIS) under NEPA takes 4.6 years, the highest it has ever been. NAEP also estimated that the time to complete an EIS increased by 34.2 days each year from 2000 to 2012. (146-NAM)

Another respondent wrote that, with respect to individual permits under CWA Section 404 for dredge and fill activities, this "process can take 4 years even if a full Environmental Impact Analysis is not required." (43-Mosaic) Other respondents also discussed the increased costs and significant manufacturing and construction delays as a result of NEPA. (10-PCBI, 42-Novelis, 43-Mosaic, 46-ATT, 71-Whirlpool, 83-TM, 86-IPAA, 96-NMA, 101-AA, 114-AGC, 115-HSIA, 125-BP, 136-AFPM, 146-NAM, 159-VI, 172-VI)

Regional Haze Requirements

In 1999, the EPA announced a major effort to improve air quality in national parks and wilderness areas. The Regional Haze Rule (RHR) calls on states, in coordination with the EPA, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. In 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smoky Mountains and Shenandoah National Park.

One of the most significant concerns with the RHR is that the requirement to reach "natural conditions" in visibility (defined as visibility in pre-industrial America) in the National Parks by 2064 may be unreasonable given the global nature of air quality and current operation and needs of our society. (148-TSGTA; see also 69-Domtar, 86-IPAA, 89-IECA, 100-ACA, 101-AA, 102-Renfro, 123-3M, 125-BP, 170-APF) To reach natural conditions, the EPA has been implementing restrictions in NOx emissions and emissions from electric generators, and forcing states to impose high cost, low benefit pollution controls. In doing this concerns were raised that EPA is interfering with implementation of this rule, for which States have the primary role in determining how best to make emissions reductions and define their own 'glide-path' to achieving the goal.

Crystalline Silica Standard

Silica can be found in a number of manufacturing operations, including foundries, glass making, paint manufacturing, porcelain manufacturing, and brick manufacturing. (107-COC) In 2016, an OSHA rule was finalized[41] which cut in half the permissible exposure to crystalline silica (for general industry and maritime) from 100 to 50 micrograms per cubic meter.[42] Compliance is required within 2 years after the effective date (2018).

Industry respondents suggest the standard is simply too stringent and will be difficult, costly or impossible with which to comply. According to NAM the rule requires "extensive and costly engineering controls. . .exposure monitoring, medical surveillance, work area restrictions, clean rooms and recordkeeping" (146-NAM) Respondents also state that the standard "could force manufacturers to shut their doors" or "could potentially cause several types of manufacturing to leave the United States." (146-NAM, 107-COC) The U.S. Chamber of Commerce indicates that the previous standard was highly effective, reducing deaths from exposure to silica by over 93% since 1968, and this new standard is being challenged in court (to determine if OSHA demonstrated "significant risk," and whether compliance with the rule "is technologically and economically feasible"— a "statutory requirement for an OSHA standard)." (107-COC) Respondents have suggested that the rule should be rescinded or reviewed.[43] (146-NAM, 107-COC)

[41] 81 FR 162885 (March 25, 2016).

[42] Paul R. Noe, "Smarter Regulation for the American Manufacturing Economy," American Forest and Paper Association, September 14, 2016.

[43] 146-NAM, 107-CoC, NFIB, Problem Regulations, January 24, 2017.

Department of Labor Overtime Rule

The new overtime rule raises the salary level required for exemption from overtime pay of salaried white collar employees from $23,660 to $47,476.[44] A number of respondents suggested that the salary level for this exemption was too high, the rule exceeded statutory authority, and the automatic escalation of this salary threshold over time would be too rapid. (146-NAM, 6-NFIB, 39-IPC, 107-COC, 120-NTMA/PMA) The rule has been preliminarily enjoined by a district court, and the federal government has appealed this decision.[45]

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act's (CERCLA) major emphasis is on the cleanup of inactive hazardous waste sites. CERCLA gives the President authority to clean up or ensure the cleanup of these sites through "removal" and/or "remedial" actions, generally referred to as "response" actions, to address threats to human health and environment. CERCLA provides for cost recovery from potentially responsible parties, including current and former owners and operators of the facility, along with parties that arranged for or transported hazardous substances to the facility. Agencies provide oversight when the cleanup is pursuant to an agency order or a federal consent decree. The National Oil and Hazardous Substances Pollution Contingency Plan (NCP) outlines CERCLA's implementing regulations. Agencies follow the procedures and standards detailed in the NCP when remediating these sites.

RFI respondents raise concerns that CERCLA requirements can be extremely expensive and duplicative with other regulations. (84-Ameren, 92-AISI, 96-NMA, 101-AA, 110-Freeport, 111-GAC, 131-NMMA, 159-VI, 160-TCC) As a separate point, one respondent further stated, "under this policy, EPA routinely requires cooperating private parties to pay for duplicative and unnecessary expenses that the Agency incurs—in addition to the substantial expenditures the private parties are already undertaking in order to remediate the site. EPA's duplicative oversight activities not only increase costs, but also impede the pace of remediation by adding layers of unnecessary review. In 2015, EPA billed private parties $106.4 million for agency oversight—a substantial amount of overhead costs and resources that are better spent directly on cleanup activities."[46]

Spill Prevention, Control, and Countermeasures

EPA, within the CWA, requires non-exempt facilities to prepare Spill Prevention, Control and Countermeasure (SPCC) plans to prevent the discharge of oil from non-transportation related onshore and offshore facilities into U.S. navigable waters or adjoining shorelines. The SPCC rule applies to owners or operators of non-transportation related facilities who drill, produce, store, process, refine, transfer,

---

[44] For more information, see https://www.dol.gov/whd/overtime/final2016/.

[45] *Nevada v. DOL*, E.D. Tex., No. 4:16-cv-00731, *motion granted* 11/22/15.

[46] U.S. Environmental Protection Agency, Superfund Remedial Annual Accomplishments, "Fiscal Year 2016 Superfund Remedial Program Accomplishments Report."

distribute, use or consume oil or oil products that meet at least one of the capacity thresholds and have the potential to discharge oil to U.S. navigable waters or adjoining shorelines.

One primary concern with SPCC is the overlap with other federal regulations. The most frequently raised overlap mentioned was the duplication of the SPCC with the Stormwater Pollution Prevention Plan (SWPPP). The duplicative effort required by these two regulations adds costs to the manufacturer and delays construction and operations. (37-ILMA, 76-Boeing, 101-AA, 106-AFS, 107-CoC, 114-AGC, 127-PCA) According to one respondent, "construction site operators are required to develop plans for preventing, containing, and cleaning up oil spills under the NPDES and SCPP regulations. If a construction site operator has a SWPPP that addresses oil storage and spill control, containment and cleanup measures, then EPA should allow the jobsite SWPPP to also satisfy the agency's SPCC requirements. Otherwise, this is double regulation — and each plan carries significant costs for the contractor to develop. The list of overlapping requirements includes documentation, management certification, site maps and diagrams, inspection and maintenance, recordkeeping, training, designated employees, notification procedures and response obligations. The U.S. Coast Guard also is involved in spill plans if the project is on/over water, which add further delays."

Equal Employment Opportunity Commission Reporting Requirements

The Equal Employment Opportunity Commission (EEOC) recently revised its EEO-1 reporting requirements so that beginning in 2018 employers must submit more comprehensive and detailed information that will be used to enforce prohibitions against employment discrimination and address discriminatory pay practices. Employers with 100 or more employees (both private industry and federal contractors) will be required to submit data on employees' W-2 earnings and hours worked by ethnicity, race, and sex, sorted into 10 job categories. Responding organizations are concerned with the additional time and resources that they will need to spend on this form and estimate that the number of reported entries will increase from less than 200 data points to over 3,000. (107-COC, 137-MEMA, 119-AGC, 77-CIRT, 66-ARTBA, 37-ILMA) Furthermore, responding organizations do not believe that the expanded data collection will provide useful information needed to enforce discriminatory pay practices. (107-COC, 137-MEMA, 119-AGC, 77-CIRT, 66-ARTBA,37-ILMA) Finally, the additional reporting may put a company at risk of publicly disclosing employees' private information and/or proprietary company information. (146-NAM, 66-ARTBA, 37-ILMA)

Food Safety Modernization Act

Over the last several years, the Food and Drug Administration (FDA), part of the Department of Health and Human Services (HHS), has issued several regulations to implement the Food Safety Modernization Act (FSMA). Some portions of the new regulations are complex, and a misinterpretation could cause potentially negative consequences for a company. One such regulation, Mitigation Strategies to Protect Food Against Intentional Adulteration (IA rule), is aimed at preventing intentional adulteration of food intended to cause wide-scale harm to public health, including acts of terrorism targeting the food supply.[47] The regulation imposes significant new requirements on manufacturers of human food, including maintaining certain records. FDA should delay the compliance dates for the IA rule until it has revised the regulation to provide for more flexibility and greater focus on risk-based methods of preventing intentional adulteration of the food system. (98-IDFA)

As manufacturing and agricultural processing continually evolves, the FDA should ensure that regulatory requirements are flexible and able to adapt to science and innovation. Many agriculture processing companies sell secondary products (e.g., germ, feed, meal) from facilities which were not designed to handle these ingredients using the same standards for ingredients intended for human consumption. In the new FSMA foundational regulations, "manufacturing/processing" has been broadly defined around different activities conducted on food. The "farm" has a narrower definition. As a result, numerous activities that farms normally use to prepare a food crop for trade as Raw Agricultural Commodities (RAC) can be considered activities that transform the crop into a "processed food." A farm conducting these activities could be considered a manufacturer/processor and would be subject to food facility registration and to new requirements for "good manufacturing practices" and preventive controls. Current regulations will require some manufacturers to update facilities or adjust business practices to comply with good manufacturing requirements. There is a concern that such requirements are unnecessary and will result in lost jobs and lost opportunities for manufacturers. (146-NAM, 122-AHPA)

Additionally, the FSMA requires sellers (farmers and food processors) to obtain from their customers (downstream food processors and distributors) certain "written assurances" on an annual basis. With these written assurances in place, the sellers are provided a certain amount of regulatory relief — relief which in many cases is essential to the continued existence of their business, since according to respondents it is nearly impossible (not just inefficient or uneconomical) for the firm otherwise to comply with the applicable regulations. An analysis by the Grocery Manufacturers Association (GMA) determined that just the provisions in 21 CFR § 117.136 would require individual firms to obtain thousands or even millions of assurances every year. Therefore, the FDA should remove these unnecessary and burdensome provisions from the regulations. (70-GMA)

Commenters raised other concerns about FDA regulations, such as the Nutrition Labelling Standards. To provide consumers with clearer nutritional content information for food, based on updated nutrition research and public health information, the FDA issued a regulation in May 2016[48] that would require changes to the Nutrition Labeling, 21 CFR. §101.9 and Reference Amounts Customarily Consumed Per Eating Occasion (serving size) regulations, 21 CFR. § 101.12. These changes represent the first major update to the Nutrition Facts label in over 20 years and would require a massive overhaul to the food package label and information provided to consumers. FDA provided food manufacturers until July 26, 2018 to make this change even though FDA's own Regulatory Impact Analysis for this change estimated the cost to industry to comply in two years would be $4.6 billion, whereas the cost to comply in four years would be $2.8 billion.

[47] 81 FR 34165 (May 27, 2016).
[48] 81 FR 33741 (May 27, 2016).

In other words, just extending the compliance deadline from two to four years saves $1.8 billion. The challenge of compliance is compounded because FDA has yet to issue final guidance on the types of dietary fiber it considers to meet the new definition, 21 CFR §101.9(c)(6)(i), and information on calculating added sugars for some types of food, 21 CFR § 101.9(c)(6)(iii), which must be listed in the new label format. Additionally, the USDA is mandated by law to issue a regulation requiring the disclosure of the content of genetically modified ingredients in all foods by July 29, 2018, three days after the compliance deadline for the Nutrition Facts updates. FDA should extend the compliance date for this labeling update until May 2021 to ease the regulatory burden. Additional compliance time would allow companies to coordinate labeling updates, provide consumers with clear information to help them make healthy choices and avoid wasteful spending on duplicate relabeling schemes that would be required during the next four years. Additionally, USDA and FDA should work together on timing of compliance with these required changes so that manufacturers will only be required to make one label change. (98-IDFA, 146-NAM, 122-AHPA, 70-GMA, 74-Knouse) Other regulatory redundancies should also be eliminated between FDA, USDA, EPA, and other federal agencies. (53-ACMA, 74-Knouse, 64-TFI, 85-NOPA)

Overview of Regulatory Reform

Over the years, much effort has been spent on regulatory reform by think tanks, industry associations, and government agencies. Yet, for several reasons, the burden for manufacturers continues to grow. Through the process of writing this report it became clear to the Department that at the manufacturing plant level, there are significant opportunities for burden reduction. Respondents provided numerous examples of impractical, unrealistic, or onerous requirements and of processes that make permitting unnecessarily complex and time consuming.

Regulators and manufacturers working together can eliminate unnecessary regulatory burdens. These unnecessary burdens can be eliminated if regulators work with industry to apply commonsense and practicality to regulations and requirements to more closely reflect real world operating conditions. Responses revealed the need to reform the permitting process and existing rules and to reduce the current compliance burden without impacting benefits. Responses to the RFI revealed the need to also reform the process for new rulemakings.

Past Attempts at Regulatory and Permitting Reform

Over the years there have been many regulatory reform efforts. Prior reform efforts have prescribed principles for effective rulemaking, including the use of cost-benefit analysis (CBA), examining alternatives to regulations, and retrospective reviews. Yet the regulatory burden has only grown more onerous.

Factors that have undermined prior reform efforts include: indeterminate and underdeveloped cost-benefit models, methodologies and assumptions; a lack of agency effort to comply fully with all rulemaking requirements; and a lack of power and resources in oversight organizations to compel compliance with these principles.

Agency cost-benefit analyses sometimes lack transparency and make self-serving assumptions regarding important direct and readily quantifiable costs. Moreover, technically challenging and resource-intensive intangible, indirect, and cumulative impacts are often not meaningfully addressed. This includes opportunity costs such as impacts on innovation and productivity, despite the potentially far-reaching benefits.

Regulatory reforms also have required the consideration of alternatives — including market-based incentives (rather than a command and control approach). Despite these efforts, agencies tend to make assumptions that cast the politically preferred alternative in a favorable light. As a result of these factors, the cost-benefit models often fail in certain circumstances to capture the true costs of implementing regulation. For some important federal regulations (e.g., listing a species under the Endangered Species Act), a cost-benefit analysis is not required at all.[49]

Moreover, current application of principles of regulation often results in unnecessary, unreasonable, outdated, and impractical requirements that are of concern to manufacturers. Agencies frequently attempt

[49] Independent regulatory agencies are not required to provide a cost-benefit analysis.

to skirt the federal requirement to "maximize net benefits" prescribed in EO 12866[1] by over-weighting of qualitative benefits to justify quantitative costs. "Real-world" impacts of regulatory burdens are in many cases not adequately addressed. Regulatory agencies too often are not sensitive to concerns from manufacturers about overly cumbersome constraints and costs, a failure of agency culture and leadership.

The Need for Collaboration between Regulators and Manufacturers

Respondents provided a multitude of examples of unnecessary compliance burdens. Our review is not able to evaluate the substance of all the complaints or the soundness of all recommended solutions, but the large number of examples suggests there is a significant opportunity for regulatory reform.

Rather than consider the retrospective review process as a re-confirmation of the validity of a regulation, agencies should adopt the practice of working together with the regulated community — manufacturers, in this case — to understand real world burdens (including unintended ones) and to devise potential alternative, commonsense solutions collaboratively. Given the myriad challenges in creating a good rule, lookbacks with stakeholders could give agencies another opportunity to work toward the goal of avoiding regulations that impose unwarranted burdens.[50]

This suggestion fits with EO 13777[51]: "In performing the evaluation [of existing regulations], each Regulatory Reform Task Force shall seek input and other assistance… from entities significantly affected by Federal regulations…" In addition, former Office of Information and Regulatory Affairs (OIRA) head Cass Sunstein recently wrote: "Because the White House itself lacks the capacity to scrutinize the stock of existing regulations, the Trump administration was smart to call for task forces within each agency to do that — and to require them to engage with the public to see which regulations are really causing trouble."[52]

This is also very much in line with other nations' reform policies in which government works with the regulated community to identify unnecessary burdens. As one former UK government official said, "In the UK, by focusing on how we regulated, rather than just what we regulated, we were able to drive enormous cost reductions without sacrificing protections. By simplifying forms and processes, compliance became much less costly without any underlying regulatory changes or compromising mission."[53] This official also observes that the cultural change required to accomplish this reform should not be underestimated: "Those who work in regulatory policy often focus on designing new regulatory ideas. Typically, they don't systematically look for ways to reduce the costs of regulations that are already on the books."

RFI respondents also call for agencies to review existing regulations with stakeholders.[54] One association suggested that a better relationship with manufacturers may help agencies to reduce regulatory burden

[50] EO 12866: "Each agency shall tailor its regulations to impose the least burden on society…", September 30, 1993.

[51] EO 13777 (March 1, 2017).

[52] Cass R. Sunstein, "Trump's Safe and Sane 'Regulatory Reform' Idea," *Bloomberg*, March 3, 2017.

[53] Jitinder Kohli, "What President Trump Can Learn From The UK About Reducing Regulations," Forbes, January 27, 2017.

[54] For example, note the following RFI responses: 48-RFF with regard to EPA and NAAQS; 133- PIA with regard to EPA and flexible air permitting; and 53- ACMA with regard to EPA emission modeling (see Docket ID "DOC-2017-0001," at www.regulations.gov).

without sacrificing their missions: "state regulators [in Indiana, Louisiana, Ohio, and Texas are] more knowledgeable about . . . steel manufacturing, or more willing to take the time to become knowledgeable. . . Armed with superior knowledge, state personnel often understand the impracticability or inapplicability of certain controls or requirements, and are more often open to allowing alternate compliance options that reach the same goal through the use of less burdensome means." (112-SMA)

Examples from RFI responses of commonsense suggestions for reform (that might surface during a collaborative lookback) include the following (organized by category):

<u>Lack of Knowledge about How Industry Operates</u>

- "EPA's Risk Management Program rule and other regulations require manufacturers to interact with Local Emergency Planning Committees (LEPCs). [But] there are no LEPCs in many areas. Of the 100 counties in North Carolina, for example, only 40 have functioning LEPCs." (53-ACMA)

- [Regarding OSHA's Hazardous Air Contaminants Standards; for employers seeking to meet through an engineering calculation or evaluation they conduct] "Powered ventilation is generally the most effective and widely used technology to limit exposures to hazardous airborne substances in composites manufacturing workplaces. PPE [personal protective equipment] is <u>also</u> employed when the nature of the work limits the ability of employers to achieve safe exposure levels via ventilation alone. However, several industry employers have been cited by OSHA for using PPE when they have not "proven" that engineering control <u>would not be sufficiently effective.</u>. . ." (53-ACMA)

- "FDA regulatory provisions implementing the Food Safety Modernization Act (FSMA) require sellers (farmers and food processors) to obtain from their customers (downstream food processors and distributors) certain "written assurances" [re food safety hazards] on an annual basis. . . An analysis by the Grocery Manufacturers Association determined that just the provisions in [one of several specific regulations] would require individual firms to obtain thousands or even millions of assurances every year.. . ." (122-AHPA)

- [Regarding Non-Complying Lots -- 40 CFR. § 770.20(f), which requires fabricators that received notification from a producer of panels that failed an emissions test, to inform customers that their finished products contained these panels.] "First, by the time the fabricator receives the panel producer's notification, the panels almost certainly no longer exist as panels. Instead, the fabricator will almost certainly have cut up the affected panels it received into component parts, incorporated those component parts into finished goods, and shipped those finished goods. Second, the affected panels are untraceable once they are incorporated into finished goods. A fabricator does not track which panels go into which finished goods... Third, in the fabrication process the panels are covered with veneers or other coatings. This means that it is no longer feasible to test the panels accurately for compliance with the emissions limits. Fourth, the fabricator's notification is very likely to be completely unnecessary, because by the time the customer receives its notification, the affected panels will probably have aged to the point that they now meet the emissions limits." (67-AHFA)

- [Regarding CWA §316(b)- Cooling Water Intake Structures (CWIS) -- Entrainment "Best Technology Available" (BTA) for facilities withdrawing less than 125 MGD] "Facilities withdrawing less than 125 MGD are not required to submit entrainment information however the permitting authority is still required to make a determination about the BTA to minimize entrainment... Permitting authorities generally lack the technical expertise in such areas, so it requires the permittees to provide the permitting authority with adequate technical information to support the BTA determination. A 52-week entrainment study can range from $140,000 to $410,000." (147-US Steel)

- "([Regarding] Toxic Substances Control Act (TSCA) regulation... Chemical Data Reporting (CDR) regulations require exceptionally detailed monitoring, recording, and reporting of the chemical make-up of our members' steel and steel coatings, raw materials...) It is overly burdensome to the steel industry to report on the general safety of a product that has been widely produced for several centuries and whose chemical makeup is well known and that poses little risk from exposure." (92-AISI)

- "EPA should ensure remediation cleanup standards are reasonably achievable... for example cleanup standards may be set below background concentrations that can never be achieved at a cleanup site until sources in the wider area are controlled...." (76-Boeing)

- "FDA has formally acknowledged under various circumstances that reliance on batch records is an accurate and practical method for assuring that finished food products meet required compositional specifications for ingredients that are chemically complex or for which no validated test method exists... [But] during inspections of firms under 21 CFR Part 111, FDA often pushes firms to implement expensive chemical testing for such ingredients (which would cost at least hundreds and potentially thousands of dollars per batch of product)—or to prove that no such chemical test method exists (an exercise that is expensive and pointless, since it's impossible to prove a negative and it is very rare for valid test methods to exist for chemically complex food ingredients, especially in a chemically complex matrix)." (122-AHPA)

Inconsistent Enforcement

- "Differential enforcement of a regulatory requirement across geographies (i.e., inspectors interpreting a regulation differently in two different manufacturing locations) is so troubling to compliance officials."[55]

[55] National Association of Manufacturers, "Holding US Back: Regulation of the U.S. Manufacturing Sector," prepared by Pareto Policy Solutions, LLC.

- "Inconsistent Federal implementation of the RCRA Corrective Action process from region to region and site to site… causes… increased cost and lost opportunities due to unpredictable or longer time periods for addressing impacts to the environment." (147-US Steel)

Antiquated Rules

- "The current Leak Detection and Repair (LDAR) rules require point-by-point monitoring for leaks (Method 21) for every LDAR component (valves, pumps, compressor seals, pressure relief devices, etc.). This is very time consuming and inefficient. Infrared cameras (IR camera) are now voluntarily used in manufacturing to detect leaks much more quickly and efficiently. The use of these IR cameras should be a technology option to replace the current antiquated LDAR rules." (89-IECA)

Technology Requirement is Too Expensive or Unproven (Unrealistic Assumptions or Cost is Too High)

- "FDA regulation 21 CFR 111, Current Good Manufacturing Practice (cGMP) in Manufacturing, Packaging, Labeling, or Holding Operations for Dietary Supplements, includes Section 111.605 (a) and (b) … requires that all electronic records comply with 21 CFR 11, a burdensome and complex requirement to validate computer systems that was developed for drug manufacturers. The software and hardware validation requirements are costly, difficult to maintain, and fail to provide added security… Small and midsize dietary supplement manufacturers that lack the resources to validate computer systems are burdened with maintaining hard copies and using hand-written records, which is a costly, inefficient, and unnecessary clerical obligation.…" (63-CRN)

- "The PSD BACT evaluation process, spelled out through EPA guidance, should not include unproven technologies employed in other countries that have not been demonstrated as commercially feasible or effective at controlling emission in the U.S. Requiring domestic facilities to conduct technology reviews and costly feasibility analyses of technologies utilized in countries that do not have the same rigorous air pollution control and permitting requirements, places unreasonable permitting demands and delays on the already lengthy U.S. permitting process." (92-AISI)

Complex, Onerous Processes, e.g., Unnecessary Recordkeeping

- "In past years we dedicated the majority of our environmental resources to emission reduction equipment that has dramatically reduced our impact on the environment. In more recent years, the majority of our environmental resources have been dedicated to monitoring and record keeping. Reducing the frequency of monitoring, and reducing the amount of recordkeeping and reporting would be very beneficial. We believe that we can adequately demonstrate ongoing and continuous compliance with reduced levels of monitoring and recordkeeping." (112-SMA)

- "For permitting projects… USEPA and States ask for endless pieces of information that are not necessary to issue a permit or approve a submittal; and are beyond what is required by statute and the implementing regulations. Frequently, the agencies indicate the information is needed to address questions or concerns from third parties—'we need this information because somebody may ask about it or because it would be nice to know.'" (147-US Steel)

- "Review and streamline data requirements to ensure that only data that is required for a permit decision is required to be submitted." (79-Northrup Grumman)

- "Record Keeping Mandate on EPA Air Permitted Standby Engines: 40 CFR Part 51 (Subpart A)… Standby engines rarely operate but companies, by law, are required to report emissions data… in 2016, a company reported total emissions from emergency engines (generators and fire pumps) as follows. [Table shows emissions sum= 0.005716 tons per year) The company estimates that it takes $500 (5 times $100 per engine) per year to monitor, report, and do maintenance as EPA instructs them to do. Given the costs and given the emission volume, it cost about $90,000 per ton of emissions." (89-IECA)

Review of Existing Regulations

Reducing the existing regulatory burden is perceived by some respondents to be more critical than reforming the process of creating new regulations.[56] Retrospective reviews of existing regulations have been required since the Carter administration, but like reforms for rulemaking processes, retrospective reviews often do not receive appropriate emphasis.

The need for retrospective review is straightforward. Although public engagement is critical before rules are written, retrospective reviews give agencies and the regulated community an opportunity to assess a regulation's actual impact — costs and benefits — using real numbers and experiences. "Lookbacks" would allow agencies to examine unintended costs as well as identify (and ameliorate) unnecessarily burdensome compliance requirements.

There are many reasons why meaningful retrospective reviews are rare. The overriding reason is probably the same as for new rules (above): there are "insufficient incentives"[57] to overcome the strain on resources required to conduct these reviews. Some sources suggest that agencies are biased and that "External funds must be provided to give disinterested researchers an incentive to conduct unbiased and independent studies."[58]

---

[56] National Association of Manufacturers, "Holding US Back: Regulation of the U.S. Manufacturing Sector," prepared by Pareto Policy Solutions, LLC and NERA Economic Consulting, "Macroeconomic Impacts of Federal Regulation of the Manufacturing Sector." Prepared for the Manufacturers Alliance for Productivity and Innovation (MAPI), August 21, 2012.
[57] Winston Harrington, "Grading Estimates of the Benefits and Costs of Federal Regulations: A Review of Reviews," Resources for the Future (RFF) Discussion Paper, September 2006.

[58] Ibid.

Several models were suggested such as creating another non-partisan entity like the Congressional Budget Office (CBO) which avoids making policy recommendations and focuses on unbiased analysis; and, in this case, the new entity would identify regulations that are in need of reform or elimination.[59] Regulatory Reform Task Forces (RRTFs) have been formed (via EO 13777) within each agency and they can help play this role if members are given sufficient autonomy and capacity to focus primarily on regulatory reform activities. Because of the limited resources historically made available for reviewing existing regulations, and the tendency for agencies to be biased in favor of their respective regulatory authorities, constant attention and oversight of their efforts will be required in order to make sufficient progress.

President Trump's Executive Order 13771 also provides the forum and structure for an ongoing retrospective review by requiring agencies to implement a "2 for 1" (also known as "one-in, two-out," or Cut-Go) mandate that requires the elimination of regulations or costs of existing regulations to offset the burdens of a new regulation. Countries such as the United Kingdom, Canada, the Netherlands, and Australia have implemented a version of this program.[60] In Senate testimony, Senator Mark Warner claimed that the United Kingdom went from being the epitome of regulatory oppression to surpassing the United States in international competitiveness in part because of its ongoing PAYGO-type policies.[61]

Reforming the Permitting Process

According to respondents, "permitting requirements are numerous and quite onerous." (112-SMA) Permitting — particularly related to the Clean Air Act and Clean Water Acts — was the most frequently cited concern, and often identified as a top priority regulatory burden. The Clean Air Act New Source Review (NSR) program was described by many as the most significant permitting challenge and impediment to construction of new manufacturing plants and modernization of existing facilities.

Beyond the reforms to specific regulations and permitting processes called for in this report, there are two overarching problems that must be addressed throughout federal permitting. The first is overlap, duplication and lack of coordination among agencies, permitting processes, and reporting requirements. The second is uncertainty in the permitting processes.

Overlap, Duplication and Coordination

Many RFI respondents raised concerns that EPA "second-guesses" state decisions. (170-APF) "Even in cases where a state issues CAA permits under an EPA-approved [state implementation plan], there are instances when decisions made by the permitting authority are re- evaluated and revisited by EPA, duplicating the efforts of the agencies and adding uncertainty for the permittee." (126-API)

---

[59] Philip A. Wallach, "An Opportune Moment for Regulatory Reform", Brookings, April 2014.

[60] All 4 nations focus on cutting costs not number of regulations; Australia, Canada, and the Netherlands focus on red-tape or administrative costs; the United Kingdom's definition is broader but focuses heavily on red-tape.

[61] How Best to Advance the Public Interest: Hearing before the Committee on Homeland Security and Governmental Affairs, U.S. Senate, 112th Congress, (2011)

In addition, there were examples cited of "overlapping jurisdiction of federal agencies and programs" (146-NAM) such as:

- "Aspects of RCRA and CAA permits" (158-CKRC)
- "NSR and Title V permits can have significant overlap…" (109-Valero)
- "EPA and the U.S. Army Corps of Engineers: Water and wetlands." (146-NAM)
- "EPA's Integrated Risk Information System, EPA's risk evaluation programs under the Toxic Substances Control Act, the CDC's Agency for Toxic Substances and Disease Registry Toxicological Profiles program, and NIH's National Toxicology Program Office of Report on Carcinogens have largely redundant missions." (53-ACMA)

In some cases, multiple regulations or agencies require the same information: "Companies are often required to separately report the same information to multiple regulatory offices and programs, including at the federal, state and local level. For example, data on air emissions are typically reported as part of permit compliance reports, to state air emission inventories, and to EPA's Toxic Release Inventory program." (152-AWC)

A related issue is the lack of coordination of the review process when more than one agency is involved: "US Army Corps of Engineers has authority for Section 404 permitting. However, in order to get the permit, review and consultation is required for multiple other federal agencies… all raising issues about maintaining sufficient bird and fish habitat." (126-API)

Overlap, Duplication and Coordination — Potential Solutions. Many respondents suggested that federal agencies (primarily EPA) should defer to states in order to: "…reduce, if not eliminate, federal second-guessing. Substitute individual permit oversight with federal programmatic overview of state adherence to permitting requirements. States should be evaluated on how their program is performing, not micromanaged on each and every permit decision." (170-APF)

In other cases, where multiple agencies must be involved, many respondents suggested something similar to FAST-41 type provisions:

- "Designate Lead Agency to coordinate responsibilities among multiple agencies involved in project reviews."
- "Provide for concurrent reviews by agencies, rather than sequential reviews."[62] (107-COC)

[62] The Water Resources Reform and Development Act of 2014 is another FAST-41 type model for permitting reform according to 109-Valero: "…overhauled the Corps' planning process by creating a strict three-year deadline and $3 million federal cost limit for feasibility studies. It required different levels of Corps review to occur concurrently and eliminated duplicative requirements, such as multiple cost-estimates and a reconnaissance study. [Also] designated the Corps to be the lead agency coordinating reviews for civil works projects.…"

Respondents also offered the following best practice examples:

- "Ohio EPA piloted a program in which it took normally sequential steps in permit processing and executed them in parallel, significantly reducing overall permit processing time." (170-APF)

- "Indiana Department of Environmental Management's air program processes construction permit applications and associated Title V permit modification for projects concurrently.. . ." (147-US Steel)

- "The California Unified Program Agency (CUPA) consolidates hazardous waste and hazardous materials requirements of multiple programs into a single regulatory entity. The result is simplified permitting, reduced regulatory complexities and reduced management burden." (79-Northrup Grumman)

One association suggested a "reporting portal" to be created by EPA with state and local regulators to "allow manufacturers to report information needed by regulatory programs only once." (152-AWC)

Several RFI respondents suggested that a specific coordinator is needed, such as a federal office responsible for permit coordination (106-AFS), or an EPA ombudsman: "This supervisory body could [provide] the regulated community with a means for coordination across various environmental media (water, air, etc.) and across various agencies (e.g., EPA, Army Corps of Engineers, Fish & Wildlife), perhaps even including state and local agencies or authorities." (76-Boeing)

Uncertainty Related to Permit Processes

Permitting challenges are exacerbated by uncertainty, as addressed in many of the RFI respondents complaints. Uncertainty comes from inter-related issues driven by complexity such as "case-by-case" or "one-off" reviews, which often "reinvent the wheel." There is also a general lack of consistency, which then contributes to uncertain timelines, which itself is exacerbated by the threat of delay driven by public protest/litigation. This complex situation is then made more uncertain by lack of transparency/poor communication. While uncertainty is also a problem in non-permitting regulations (discussed above), it appears to be a significant and systemic problem in environment-related permitting: "Environmental permitting has many sources of uncertainty, including . . . timing, procedures, the roles of various agencies in multi-agency review projects, and the data that the permitting authorities use and rely upon in making permitting decisions. Often, this variability is based on the views and expectations of a particular regional office or specific employee or office within EPA. Other times, the requirements can apply Agency-wide yet still create uncertainty. EPA, for example, is inconsistent in its data demands and the procedures by which it approves projects...." (112-SMA)

Environmental permitting is so complex that respondents described having to hire several consultants and lawyers to help "navigate" the "elaborate mazes" that permit regulations have become. (170-APF) Moreover, this appears to be true of "even simple modifications" to regulations. (112-SMA) One association wrote, "Obtaining a permit for just one CAA program alone (the NSR program) can require the permittee to review nearly 700 posted guidance documents...." (170-APF) For manufacturing firms, the uncertainty of the permitting duration, which can take years, may be the greatest challenge. "The lack of certainty as to when the permit will be issued... create(s) significant burden, compliance difficulty, and business uncertainty...." (126-API) Permitting delays are partly driven by complexity and lack of coordination as discussed above. But some respondents blamed agency staff for contributing to the problem, claiming staff can "sit on an application until their allotted time is almost up before looking at it regardless of how minor or simple the task." (114-AGC) On the other hand, other respondents claimed that delays are sometimes due to insufficient staffing resources at permitting agencies. (79-Northrup Grumman; 126-API; 123-3M)

Delays are not only driven by the agency or agencies. Lawsuits or "not-in-my-backyard activism" (107-COC) are a significant permitting issue: "Even where a permit remains valid pending resolution of the litigation, significant uncertainty can be introduced into the process of building or expanding a facility and it can take years to resolve all issues." (136-AFPM) While this is not under the control of regulatory agencies, it does increase the uncertainty for manufacturers in making investment decisions.

Lastly, according to respondents, EPA's lack of straightforward communication adds to manufacturers' burden: "EPA does not provide clarity on its procedures and information requirements. These transparency problems are significantly compounded when EPA changes its requirements through Agency-generated guidance without notice to the applicants or the ability to comment on, or ask questions about, the guidance." (112-SMA) As one example, an association explained that a Congressional requirement that EPA publish all state implementation plans (SIPs) was put in place "because it was virtually impossible to determine which regulations were currently approved as part of the SIP. This lack of transparency serves to delay projects simply because discerning what regulations apply presents its own challenge."[63]

Uncertainty — Potential Solutions. FAST-41 is often praised as a step in the right direction for permitting reform. Established under Title 41 of the Fixing America's Surface Transportation (FAST) Act (42 U.S.C. § 4370m), FAST-41 was designed to improve the timeliness, predictability, and transparency of the federal environmental review and authorization process for "covered" infrastructure projects.[64]

FAST-41 created a new Federal Permitting Improvement Steering Council (FPISC), with representation from Deputy Secretary-level members and led by a presidentially-appointed Executive Director. It also created agency Chief Environmental Review and Permitting Officers (CERPOs). Covered projects voluntarily gain access to improved authorization and environmental review processes such as early consultation, coordinated projects plans, project timetables, public Dashboard tracking,[65] and dispute resolution procedures.

[63] CAA Section 110(h)(1), requires *"EPA to assemble and publish all"* SIPs; but EPA is not complying. (170-APF).

[64] For more information, see https://www.permits.performance.gov/about/fast-41.
[65] For more information, see https://www.permits.performance.gov/projects.

Covered projects are defined as any activity in the United States that requires authorization or environmental review by a federal agency involving:

- Construction of infrastructure in a designated sector
- That is subject to NEPA, and
    - Does not qualify for an abbreviated review process and is likely to cost more than $200M; or
    - Is of a size/complexity likely to benefit from enhanced oversight/coordination in the opinion of the Council, including:
        - Projects likely to require an Environmental Impact Statement
        - Projects likely to require reviews from more than two federal agencies.

Infrastructure includes (with some exemptions): manufacturing projects as well as renewable energy production, conventional energy productions, electricity transmission, surface transportation, aviation, ports and waterways, water resource projects, broadband, pipelines, aviation, and any other sector determined by a majority vote of the FPISC.

The initiative is new, with the inventory of existing covered projects just added to the Dashboard in September 2016. For that reason, one commenter recommended "revisit[ing] lessons learned from FAST 41 (sic) permit streamlining later when the FAST 41 program is more mature." (128-Pugh) At the same time, the U.S. Chamber of Commerce directly asked that "the administration's permit streamlining efforts are consistent with FAST-41 activities already being administered by the Office of Management and Budget." (107-COC). NAM noted the potential value of implementing in concert Executive Order 13766, "Expediting Environmental Reviews and Approvals for High Priority Infrastructure Projects," and FAST-41. (146-NAM)

Although manufacturing is a covered sector under FAST-41, given the short history of FAST-41 and the strict definition of covered projects, the manufacturing community has yet to share in its benefits. Several of FAST-41's key provisions (107-COC) would be extremely beneficial if they were to be applied to manufacturing industry permitting:

- "Establish a permitting timetable, including intermediate and final completion dates";
- "Require that agencies involve themselves in the [permitting review] process early and comment early, avoiding eleventh-hour objections that can restart the entire review timetable"; and
- "Reduce the statute of limitations to challenge a project review from six years to two years."

RFI respondents echoed these types of recommendations. Florida offers a best practice model, illustrating that an efficient permitting process is possible: "The SNAP (Simplified Nimble Accelerated Permitting) process, used by state and municipal agencies in central Florida engages in streamlined, efficient and rapid construction permitting... transform[ing] an onerous and time consuming process into a reasonably straightforward and user friendly permit acquisition process." (79-Northrup Grumman).

A frequently discussed provision of FAST-41 — the "searchable, online 'dashboard' to track the status of projects during the environmental review and permitting process" (107-COC) — addresses transparency. In addition, a respondent cited a similar best practice in this area by a federal agency: "The FCC has most of its experimental license application process available on-line. It is easy to see that an application is in the system, and any comments or requests are also visible. The history of most experimental licenses is available, going back several years." (79-Northrup Grumman)

To address over-complexity respondents suggested various types of permitting standardization as well as best practice examples:

- "Replace uncertain case-by-case permit review programs with standardized regulatory decisions that are periodically updated through rulemaking after public notice and comment." (112-SMA)
- "Develop pre-approved specifications for permits to simplify and shorten the permit process." (79-Northup Grumman)
- Offer "general permits that companies can opt into for standard pieces of equipment...." (170-APF)
- "U.S. EPA should promote and directly facilitate issuance of innovative air quality permits by state/regional permitting authorities, especially permits that "advance- approve" changes at manufacturing facilities." (123-3M)
- Streamlined permitting for "minor" projects are offered by the Pennsylvania Department of Environmental Protection (online self-registration forms using templates) and the State of Texas (permit-by-rule program). (158-CKRC)

In addition, one respondent suggested that "Federal agencies should implement Lean [Six Sigma] practices to streamline permitting" and noted that EPA regional offices are attempting to do this. The respondent goes on to say Lean practices can help agencies reduce uncertainty and inefficiency and shorten schedules and points to the Arizona Department of Environmental Quality as having had success with Lean efforts. (76-Boeing)

In addition to reducing the time limit for challenging a permit from 6 years to 2 years as described above, there were a few other recommendations as to how to improve the processes by which permitting decisions and projects can be opposed. One association related a case where a firm settled a lawsuit brought by an environmental group even though the regulatory agency had found that the facility had done nothing wrong. The association suggested: "The applicable provisions of the major environmental statutes must be revised to introduce reasonable but tough thresholds to control the right of third parties to unreasonably intervene resulting in delays and expenses to industry. The thresholds must be based on local agency negligence, fraudulent/unlawful behavior or inappropriate influence." (89-IECA)

Also, because of the potential of a lengthy permitting process, lack of "grandfather" protection can be exploited by objectors and is a recommended reform: "Without [grandfather] protection, project opponents will have an incentive to delay the permitting process as long as possible in the hope that the area will be designated NA [nonattainment] before a final permit can be issued. A more consistent grandfathering approach would ensure that companies do not spend years trying to obtain a PSD permit, only to reach the end of the process and find they now need to get an NA NSR permit (with offsets that may not be available) rather than a PSD permit." (48-AF)

New Rules: Improving the Rulemaking Process

The Office of Information and Regulatory Affairs (OIRA) review of agency rules should be reaffirmed in a number of ways.

- Cost benefit analysis methods should be refined, and made more rigorous and enforced by OIRA, with a view toward continual improvement, including development of new methods and more thorough evidence bases.
- Cumulative costs should be rigorously weighed where appropriate.
- Regulations should not impede innovation.
- There should be meaningful public engagement prior to issuing significant proposed rules.
- Regulations should be more sensitive to the impact on small business.
- Regulations should only be enacted and enforced when there are adequate resources available for review, implementation and oversight.

Recommendations and Priority Areas for Reform

Through submitted comments, industry expressed clear support for the need to protect the environment, human health, and worker safety, but shared concrete, detailed concerns with how the federal government has set out to achieve those objectives through regulation, guidance documents, and other means. They identified numerous regulatory and permitting problems that include:

- Onerous and lengthy permitting processes that increase cost, add uncertainty, and inhibit investment in and expansion of manufacturing facilities;
- Inadequately designed rules that are impractical, unrealistic, inflexible, ambiguous or lack understanding of how industry operates;
- Unnecessary aspects of rules, or unnecessary stringency, that are not required to achieve environmental or other regulatory objectives;
- Overlap and duplication between permitting processes and agencies; and
- Overly strict or punitive interpretations of guidance, policies or regulations that are often counter to a pro-growth interpretation.

The Department identified twenty sets of regulations and permitting reform issues from the respondents as being a top priority for immediate consideration. Consistent with previous studies on the costs of federal regulations, comments on Environmental Protection Agency (EPA) rules dominated the responses from industry, and constitute the bulk of the Department's recommended Priority Areas for Reform.

Priority Areas for Reform

Clean Air Act

1. New Source Review (NSR) or Prevention of Significant Deterioration (PSD) permits:

   a. Enforce the one-year turnaround time on NSR/PSD permit applications.[66]

   b. Reduce statute of limitations on challenges or appeals to one year.[67]

   c. Allow non-emitting construction activities to commence prior to receiving a permit.[68]

   d. Consider options to revise the definition of Routine Maintenance, Repair & Replacement (RMRR) to provide more flexibility.[69]

   e. Promote and facilitate use of flexible permitting mechanisms associated with PSD and Title V including, but not limited to, plant-wide applicability limits (PALs) and alternative operating scenarios. As part of this, consider any regulatory or other changes (e.g., guidance) that could facilitate more widespread use of these flexible permitting tools.[70]

   f. Develop opportunities to streamline NSR applicability determinations and/or to reduce the number of facilities and projects that may be subject to NSR through evaluating and pursuing regulatory and guidance options for addressing aggregation, project netting, debottlenecking, and the methodology by which pre and post construction emissions are calculated.[71]

---

[66] EPA will coordinate with state and local air agencies, as well as EPA regional offices, to develop best practices, guidance, or regulatory revisions necessary to ensure that NSR permits are issued consistent with the 12-month timeline described in the CAA.

[67] EPA is pursuing regulatory action intended to streamline the Title V process. Congressional action would be required to reduce statute of limitations.

[68] EPA would need to review existing regulations and guidance and identify situations for which it would be appropriate to provide additional clarity and/or opportunities to begin construction without an NSR/PSD permit.

[69] Legislation would be required for a change to the statutory definition. Respondents recommended considering potential regulatory actions to provide clarification and flexibility.

[70] EPA could conduct outreach to educate sources and permitting agencies on the benefits of flexible permitting tools and also consider minor changes to PAL provisions to provide more incentives for sources to use PALs. The EPA intends to highlight and encourage use of flexible air permitting options.

[71] EPA should review existing regulations and guidance to identify opportunities to address these issues and provide more flexibility through regulatory actions. Litigation is pending over EPA's 2009 aggregation and project netting rule; this litigation is pending resolution of EPA's reconsideration process.

g. Issue guidance on modeling concurrent with promulgation of revised National Ambient Air Quality Standards (NAAQS), to ensure timely clarification on modeling required as part of a NSR application.[72]

h. Consider opportunities to "grandfather" NSR applications following revision of a NAAQS.[73]

i. Consider opportunities to emphasize key aspects of the Best Available Control Technology (BACT) analysis including, but not limited to, expectations regarding technology determinations.[74]

j. Consider opportunities to expand the purchasing offsets outside of the local areas as well as other offset related revisions which would provide increased flexibility and burden reduction.

2. Title V Operating Permits (incorporates all of the federal and state air pollution control requirements): Extend the term of the permit from 5 to 10 years.[75]

3. National Emissions Standards for Hazardous Air Pollutants (NESHAP):

   a. EPA should increase efforts to reduce costs and avoid duplicative requirements in conducting reviews of NESHAP standards.

   b. EPA should take steps to ensure that any new requirements considered under Residual Risk and Technology Reviews (RTRs) would not be redundant or unreasonably costly.[76]

4. Consider options to provide relief for facilities through affirmative defenses or other avenues to account for unforeseeable and uncontrollable emissions during periods of startup, shutdown, and malfunction (SSM). The EPA previously adopted an interpretation which exempted SSM periods from the emissions restrictions that apply under normal operating periods.[77]

5. National Ambient Air Quality Standards (NAAQS):

---

[72] EPA has committed to timely issuance of guidance.

[73] Existing regulations provide some opportunities for "grandfathering" NSR applications.

[74] EPA would need to evaluate what could be provided to streamline BACT determinations.

[75] The EPA is completing the petitions rulemaking that will revise part 70 to clarify and streamline the process by which EPA receives and reviews Title V petitions, thereby increasing transparency and efficiency for regulated entities and environmental agencies. This action will address how EPA intends to review Title V petitions in an effort to reduce opportunities to raise NSR issues in the context of Title V.

[76] Under its existing authorities EPA is taking action to harmonize NESHAP and NSPS obligations.

[77] Pending litigation in Walter Coke, Inc., et al. v. EPA, No. 15-1166 (D.C. Cir.) (challenge to SSM SIP) and in American Municipal Power v. EPA (Sup. Ct.). Whether such exemptions and affirmative defenses can be allowed under the CAA is central to the litigation.

a. EPA should develop options that consider "real-world measurements" instead of "probabilistic models" for the PSD program.[78]

b. Extend NAAQS reviews from 5 to 10 years.[79]

c. Ozone: Delay implementation of the 70 parts per billion (ppb) standard or retain the earlier 75 ppb standard. Observers stated the 70 ppb level is approaching "background" levels of ozone in certain areas.[80] The pace at which the standard is being tightened seems hurried; implementation is further complicated by measurement and air quality modeling issues, in particular accounting for ozone transported from international sources.

6. Consistent with its authorities under section 111 of the CAA, EPA should consider adding exemptions for research and development (R&D) related activities or otherwise streamline requirements for R&D activities for New Source Performance Standards.[81]

7. EPA should issue a Unified Coating Rule (UCR) that facilities could choose to meet (replacing the eight overlapping NSPS and NESHAP regulations that apply to coatings).[82]

<u>Clean Water Act</u>

8. Waters of the United States Rule: Reconsider the rule to define more narrowly "waters of the US" to exclude ephemeral tributaries. EPA and the U.S. Army Corps of Engineers (USACE) are reviewing the existing Clean Water Rule and its definitions of "navigable waters" as directed by Executive Order 13778. // On July 27, 2017, the EPA and the USACE published a proposed rulemaking to repeal the 2015 Clean Water Rule and reinstate the regulations in place prior to its issuance.[83] As indicated in the proposed withdrawal, the agencies are implementing EO 13778 in two steps to provide as much certainty as possible as quickly as possible to the regulated community and the public during the development of the ultimate replacement rule. In Step 1, the agencies are taking action to maintain the legal status quo of the rule in the Code of Federal

---

[78] The EPA is concerned that this approach would result in a directive that would impose greater costs on regulated facilities. This issue is similar to many raised in the NSR/PSD suggestion.

[79] Altering the NAAQS timeframe would require congressional action. EPA should consider opportunities to ensure that any forthcoming reviews are not redundant and are completed expeditiously.

[80] On-going litigation: Murray Energy Corporation et al. v. EPA, No. 15-1385 (and consolidated cases), (D.C. Cir.) (challenge to the 2015 ozone NAAQS).

[81] See 40 CFR sections 60.40(c) and (d); 60.292(d); and 60.332(h). EPA is evaluating its authority to exempt R&D related activities under section 111. The EPA has routinely considered adding exemptions for R&D related activities and has added specific R&D exemptions in the past.

[82] There is ongoing litigation regarding several NESHAP. EPA cannot provide specifics. EPA has court ordered deadlines to complete risk and technology reviews for several NESHAP that apply to certain coatings. EPA should consider options with an UCR to provide flexibility that encourages facilities to meet the rule by using pollution prevention approaches.

[83] 82 FR 34899 (July 27, 2017)

Regulations, by recodifying the regulation that was in place prior to issuance of the 2015 Clean Water Rule. Currently, Step 1 is being implemented under the U.S. Court of Appeals for the Sixth Circuit's stay of the rule. In Step 2, the agencies plan to propose a new definition that would replace the approach in the 2015 Clean Water rule with one that reflects the principles in EO 13778.

9. Section 404[84] and National Pollutant Discharge Elimination System (NPDES) permits: Provide permit applicants with clear descriptions of required steps and additional tools to assist them in completing the permitting process.[85]

<u>Other</u>

10. Resource Conservation and Recovery Act (RCRA): Inappropriate classifications of waste streams as "hazardous" prevent or discourage recycling, reuse or reclamation. Aggressively review lists of hazardous waste to consider delisting certain compounds/materials/liquids that could easily be reused or recycled, but for this classification.[86]

11. Revise the Crystalline Silica Standard. A 2016 Department of Labor (DOL) Occupational Safety and Health Administration (OSHA) rule was finalized which cut in half the permissible exposure to crystalline silica (for general industry and maritime) from 100 to 50 micrograms per cubic meter. Recommendation is to keep allowed level at 100 micrograms per cubic meter.[87] // DOL announced on April 6, 2017 that it would delay enforcement of the respirable crystalline silica standard for construction until September 23, 2017, to conduct additional outreach and provide educational materials and guidance for employers.

12. Revise the OSHA rule to Improve Tracking of Workplace Injuries and Illnesses by removing requirement to disclose records of workplace injuries and illnesses and to alleviate the duplicative nature of work-related injury information collection. Clarify in guidance that this rule should not undermine safety incentives and drug testing programs.[88] // DOL has proposed delaying until December 1, 2017 the initial reporting of data on workplace injuries and illnesses (Form 300A) in order to give the administration an opportunity to review the new electronic reporting requirements. The proposed five-month delay would be effective on the date of publication of a final rule in the

[84] Section 404 Permits are under the purview of the US Army Corps of Engineers.

[85] EPA and USACE should explore opportunities to truncate the permitting processes and elevate any barriers, such as needed regulatory changes, to senior leadership for consideration.

[86] In 2015 EPA published a comprehensive revision to its rules governing the recycling, reuse and reclamation of hazardous secondary materials, where these materials would otherwise become listed or characteristic hazardous wastes if discarded rather than recycled.

[87] Pending litigation. Could be modified or repealed by agency notice-and-comment rulemaking, but must remain consistent with underlying statutory provisions in the Occupational and Safety and Health Act, 29 U.S.C. § 655(b)(5).

[88] Could be modified through further notice-and-comment rulemaking (underlying statutory requirement that companies maintain certain injury records). This issue is pending litigation.

Federal Register. Furthermore, DOL has announced its intention to issue a proposal to reconsider, revise, or remove other provisions of the Improve Tracking of Workplace Injuries and Illnesses final rule, 81 FR 29624 (May 12, 2016).

13. Revise Section 1502 of Dodd-Frank Act. Remove the Securities and Exchange Commission (SEC) requirement on manufacturers to "undertake 'due diligence' on the source and chain of custody of its conflict minerals and file a Conflict Minerals Report" and to disclose publicly this information.[89] // On April 28, 2017, the SEC suspended enforcement of the rule until ongoing litigation [Nat'l Ass'n of Mfgrs v. SEC, No. 13-5252 (D.C. Cir. Apr. 14, 2014)] has concluded.

14. Rescind Section 953(b) of Dodd Frank Act which requires CEO pay ratio disclosure.[90] // On February 6, 2017, the SEC opened a 45-day comment period on unexpected challenges for compliance with the rule. Acting Chairman Michael Piwowar directed staff to reconsider the implementation of the rule based on any comments submitted and to determine as promptly as possible whether additional guidance or relief may be appropriate.

15. Do not implement Equal Employment Opportunity Commission's (EEOC) expanded requirements for hours and earnings data on EEO-1 forms. // On August 29, 2017, OMB issued a memo to the EEOC announcing a review and immediate stay of the effectiveness of those aspect of the EEO-1 form that were revised on September 29, 2016.[91]

16. Delay compliance dates for the Intentional Adulteration rule required by the Food Safety Modernization Act (FSMA). The Department of Health and Human Services, Food and Drug Administration (HHS, FDA) should rescind requirements to obtain written assurances from downstream customers on an annual basis, or alternatively consider revision of requirement to reduce frequency and burden.[92]

17. Extend compliance deadline on nutrition labeling standards from 2018/2019 to 2021. This will allow further time for the FDA to further clarify rules[93] and definitions regarding "dietary fiber" and "added sugar" required by the new label format. // On June 13, 2017, the FDA announced that the

---

[89] This would require a statutory change.

[90] This would require a statutory change.

[91] See https://www.reginfo.gov/public/jsp/Utilities/Review_and_Stay_Memo_for_EEOC.pdf.

[92] The current compliance dates are 3,4 or 5 years after the date of publication of the rule (May 27, 2016), depending on the size of the business. Administrative action would be required to effect a delay in the compliance dates for the Intentional Adulteration rule. Although FSMA required that FDA promulgate a final rule to protect food against intentional adulteration within 18 months of enactment of FSMA, the statute does not appear to specify compliance dates. Delaying compliance would require publishing a final rule; rescinding or revising the written assurance provisions would require rulemaking.

[93] The rule was promulgated pursuant to section 403(q) of the Federal Food, Drug, and Cosmetic Act, which requires certain nutrients to be included in nutrition labeling and authorizes the Health and Human Services Secretary to require other nutrients to be included if the Secretary determines that the information will assist consumers in maintaining healthy dietary practices.

compliance dates for the Nutrition Facts Label Final Rules will be extended. The FDA has not specified the length of the extension, but will announce new compliance dates in a future Federal Register Notices. FDA explained that additional time would provide manufacturers covered by the rule with necessary guidance from FDA, and would help them be able to complete and print updated nutrition facts panels for their products before they are expected to be in compliance.

Recommendations

The Department makes three broad recommendations.

Agency "Action Plans." Each agency's Regulatory Reform Taskforce (RRTF) should deliver to the President no later than December 31, 2017, an "Action Plan" to address the regulatory burden and permitting reform issues highlighted in the responses to the RFI. The relevant agencies should review all comments received in response to the Department's RFI, and particularly address the issues detailed in the section on "Priority Areas for Reform." RRTFs should prioritize a response to these particular items and should include in their action plan a description of specific actions that could be taken to lessen the burden created by the regulations mentioned in the RFI comments. In the first year, agency leadership should update the President regularly on the status of their efforts regarding these tasks. While the "Priority Areas for Reform" list is by no means comprehensive, it represents a targeted first step to quickly address the problem of over regulation.

Annual Regulatory Reduction Forum. The Department recommends creating an annual, open forum for regulators and industry stakeholders to evaluate progress in reducing regulatory burdens. There is a long-standing need for consultations with industry to identify specific actions the federal government can take to reduce unduly burdensome regulations and accelerate permitting decisions. Industry has repeatedly expressed its appreciation of the Trump Administration's regulatory reform effort and the trust it has in the Department of Commerce to listen and bring the voice of business to this effort. Because of this, the Department of Commerce recommends that it, along with other regulatory agencies, continually evaluate progress and re-attack the problem areas. Similar to Kentucky's "Red Tape Reduction Initiative," federal agencies should collect, review, and act on recommendations from industry. Input from these annual "check-ins" will guide the continuing burden reduction efforts of RRTFs and ensure regulators are moving in the right direction while allowing for policy changes as needed.

Expand the Model Process of FAST-41. The Department recommends further implementation of the streamlined permitting process created by "FAST-41."[94] The FAST Act contains various provisions aimed at streamlining the environmental review process, with improved agency coordination through creation of a Coordinated Project Plan and a Permitting Dashboard which serves as a centralized information page for pending projects, as well as opportunities to better coordinate with state environmental documentation.

---

[94] Title 41 of the Fixing America's Surface Transportation Act of 2015 ("Fast-41", codified at 42 U.S.C. § 4370m) streamlines the Federal environmental review and permitting for certain infrastructure projects. FAST-41 created an interagency Federal Permitting Improvement Steering Council (FPISC); established new procedures for interagency consultation and coordination practices; authorized agencies to collect fees to help speed the review and permitting process; and uses the Department of Transportation's "Permitting Dashboard" to track all covered projects.

The Federal Permitting Improvement Steering Council should consider including projects in an "economically significant" category. Those projects resulting in significant, immediate economic benefit to the United States should be considered for inclusion under this new category. Consideration should be extended to complex funded manufacturing projects that can demonstrate direct and indirect benefits to the domestic economy of significant value. To be eligible for the current streamlining process, projects in this sector or category would still need to meet the definition of covered project under FAST-41.

FAST-41 provides a model process that could be incorporated into other Federal legislation that governs Federal programs and requirements that apply to manufacturing facilities. To expand further the universe of manufacturing projects that benefit from streamlined regulatory approval processes, the Administration could work with members of Congress to both expand the definition of "covered project" under FAST-41 and to incorporate procedures similar to those found in FAST-41 in other legislation applicable to manufacturing projects. Expansion of the definition of covered projects to include those which result in immediate economic benefit to the United States would help to further goals of expanding the domestic economy and lessening permitting burdens for manufacturers seeking domestic expansion of their operations.

Conclusion

The domestic manufacturing sector and our broader economy are in desperate need of regulatory reforms in order to jump- start economic growth and create jobs, innovation and prosperity for all Americans. During the process of gathering information related to this report it has become apparent that we must make significant progress in improving the way government regulates the manufacturing sector. While environmental protections are of critical importance, many regulations are being enforced in a way that is limiting the growth of our economy and our global economic leadership, while in some cases regulations are providing no meaningful environmental or public health benefits. We believe prudent actions are advisable in order to return balance to regulatory procedures.

The Department believes that the recommendations contained in this report will provide a foundational base from which government can begin to approach this monumental task. These recommendations are consistent with all ongoing regulatory reform efforts, including those outlined in Executive Orders 13777[95] and 13766.[96] Working through their RRTFs, agencies must continue to shape more focused strategies for re-forming rules, guidance and policy to address the numerous challenges cited throughout this report. We hope that through highlighting these challenges it will become easier for regulatory agencies to clearly see contentious areas and work with the regulated community to resolve them in ways that unlock our economy's potential and advance the goal of job creation. Agencies must be willing to work with those subject to their rules, guidance and policy to find methods to implement existing statutes in ways that are less cumbersome and restrictive.

[95] EO 13777 (March 1, 2017).

[96] EO 13766 (January 24, 2017).

The Department looks forward to partnering with other federal agencies to continue this endeavor in the future. We are optimistic that with continued emphasis the federal government can make progress towards these goals.

Appendix

Abbreviations Used in References to RFI Responses		
RFI #	**Abbreviation**	**Respondent**
6	NFIB	Nat'l Federation of Independent Business
10	PCBI	Pennsylvania Chamber of Business and Industry
14	Chromaflo	Chromaflo Technologies
37	ILMA	Independent Lubricant Manufacturers Association
39	IPC	Association Connecting Electronics Industries
42	Novelis	Novelis
43	Mosaic	Mosaic Fertilizer
46	ATT	AT&T Services
48	AF	NSR Program paper: Art Frass, John Graham, Jeff Holmstead
51	NSSGA	National Stone, Sand and Gravel Association
53	ACMA	American Composites Manufacturers Association
56	CPA	Composite Panel Association
63	CRN	Council for Responsible Nutrition
64	TFI	The Fertilizer Institute
66	ARTBA	American Road and Transportation Builders Association
67	AHFA	Am. Home Furnishings Alliance, Kitchen Cabinet Intl. Assoc., Intl Wood Prods Assocs., Rec. Vehicle Ind. Assoc., Natl Retail Federation, Retail Industry Leaders Assoc.
69	Domtar	Domtar - Nekoosa Mill
70	GMA	Grocery Manufacturers Association
71	Whirlpool	Whirlpool
74	Knouse	Knouse Foods Cooperative Inc.
75	SLMA	Southeastern Lumber Manufacturers Association
76	Boeing	Boeing
77	CIRT	Construction Industry Roundtable
79	Northrup Grumman	Northrop Grumman Corporation
83	TM	Twin Metals

RFI #	Abbreviation	Respondent
84	Ameren	Ameren Corp
85	NOPA	National Oilseed Processors Association
86	IPAA	Independent Petroleum Association of America
89	IECA	Industrial Energy Consumers of America
92	AISI	American Iron and Steel Institute
96	NMA	National Mining Association
98	IDFA	International Dairy Foods Association
100	ACA	American Coatings Association
101	AA	Aluminum Association
102	Renfro	Renfro
106	AFS	American Foundry Society
107	COC	US Chamber of Commerce
109	Valero	Valero Companies
110	Freeport	Freeport-McMoRan
111	GAC	Graphic Arts Coalition
112	SMA	Steel Manufacturers Association; Specialty Steel Industry of North America
114	AGC	Associated General Contractors of America
115	HSIA	Halogenated Solvents Industry Alliance
116	HAFO	National Alliance of Forest Owners
119	AGC	Associated General Contractors of America
120	NTMA/PMA	National Tooling and Machining Association; Precision Metalforming Association
122	AHPA	American Herbal Products Association
123	3M	3M
125	BP	BP America
126	API	American Petroleum Institute
127	PCA	Portland Cement Association
128	Pugh	Theresa Pugh Consulting

RFI #	Abbreviation	Respondent
131	NMMA	National Marine Manufacturers Association
133	PIA	Plastics Industry Association
136	AFPM	American Fuel & Petrochemical Manufacturers
137	MEMA	Motor & Equipment Manufacturers Association
141	ACC	American Chemistry Council - Chemical Products and Technology Division
144	AFPA	American Forest & Paper Association
146	NAM	National Association of Manufacturers
147	US Steel	United States Steel Corporation
148	TSGTA	Tri-State Generation and Transmission Association
151	PESA	Petroleum Equipment and Services Association
152	AWC	American Wood Council
155	PMPA	Precision Machined Products Association
158	CKRC	Cement Kiln Recycling Coalition
159	VI	The Vinyl Institute
160	TCC	Troy Chemical Corporation
170	APF	Air Permitting Forum
172	VI	The Vinyl Institute

Note: The number associated with the respondents are the RFI ID# and can be used to access the responses, see Docket ID "DOC-2017-0001" at www.regulations.gov.

A complete list of respondents can be found at: https://www.commerce.gov/reducingburden

To: Williams, Melina[Williams.Melina@epa.gov]
From: Keller, Peter
Sent: Tue 10/3/2017 3:22:58 PM
Subject: WPL Columbia order
columbia_county_response2008.pdf

Peter Keller, PE

US EPA | OAQPS | AQPD | NSRG

(919) 541-2065

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	ORDER RESPONDING TO
WISCONSIN POWER AND LIGHT	)	PETITIONER'S REQUEST
COLUMBIA GENERATING STATION	)	THAT THE ADMINISTRATOR
	)	OBJECT TO ISSUANCE OF
	)	STATE OPERATING PERMIT
Permit No. 111003090-P20	)	
Proposed by the Wisconsin Department	)	Petition Number V-2008-1
Natural Resources	)	

ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR OBJECTION TO PERMIT

On September 2, 2008, pursuant to its authority under the State of Wisconsin implementing statute, Wis. Stat. Ann. 285.62-285.64, and regulations, Wis. Admin. Code NR 407, title V of the Clean Air Act (Act or CAA), 42 U.S.C. §§ 7661-7661f, and the U.S. Environmental Protection Agency's implementing regulations at 40 C.F.R. Part 70 (Part 70), the Wisconsin Department of Natural Resources (WDNR) issued a title V renewal operating permit to Wisconsin Power and Light (WPL) (now Alliant Energy) Columbia Generating Station (Columbia), #111003090-P20 (P20). The Columbia plant primarily consists of two 527 megawatt pulverized coal fired boiler generators, and coal handling equipment, such as conveyors and storage piles.

On September 3, 2008, EPA received a petition from David Bender of the Garvey McNeil & McGillivray, SC, Law Offices, on behalf of the Sierra Club (Petitioner), requesting, pursuant to section 505(b)(2) of the Act and 40 C.F.R. § 70.8(d), that EPA object to issuance of the Columbia title V permit. The Petitioner alleges that the permit is not in compliance with the requirements of the Act. Specifically, the Petitioner alleges that (1) the Columbia permit omits applicable Prevention of Significant Deterioration (PSD) requirements based on an erroneous legal interpretation by WDNR; (2) WDNR failed to respond to substantive comments from Petitioner regarding alleged factual errors in WDNR's PSD applicability determination; (3) the permit does not include a compliance schedule addressing opacity/visible emissions (VE) violations; and (4) the permit omits applicable requirements related to hazardous air pollutant emissions, including the requirement to submit a case-by-case maximum achievable control technology (MACT) "MACT Hammer" application.

EPA has reviewed these allegations pursuant to the standard set forth in section 505(b)(2) of the Act, which requires the Administrator to issue an objection if the Petitioner demonstrates to the Administrator that the permit is not in compliance with the applicable requirements of the Act. *See also* 40 C.F.R. § 70.8(d); *New York Public Interest Research Group v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2002).

Based on a review of the available information, including the petition, the permit record, and relevant statutory and regulatory authorities and guidance, I grant the Petitioner's request in part and deny it in part, for the reasons set forth in this Order.

STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act requires each state to develop and submit to EPA an operating permit program to meet the requirements of title V. EPA granted final full approval of the Wisconsin title V operating permit program effective November 30, 2001. 66 Fed. Reg. 62951 (December 4, 2001).

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and such other conditions as are necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable State Implementation Plan (SIP). *See* CAA §§ 502(a) and 504(a), 42 U.S.C. §§ 7661a(a) and 7661c(a). The title V operating permit program does not generally impose new substantive air quality control requirements (referred to as "applicable requirements"), but does require permits to contain monitoring, recordkeeping, reporting, and other requirements to assure compliance by sources with existing applicable emission control requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992) (EPA final action promulgating Part 70 rule). One purpose of the title V program is to "enable the source, states, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units and that compliance with these requirements is assured.

For a major modification of a major stationary source, applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review requirements (e.g., PSD). Part C of the CAA establishes the PSD program, the preconstruction review program that applies to areas of the country, such as Pardeeville, Wisconsin, that are designated as attainment or unclassifiable for National Ambient Air Quality Standards (NAAQS). CAA §§ 160-169, 42 U.S.C. §§ 7470-7479. New Source Review, or "NSR," is the term used to describe both the PSD program and the nonattainment NSR program (applicable to areas that are designated as nonattainment with the NAAQS). In attainment areas, a major stationary source may not begin construction or undertake certain modifications without first obtaining a PSD permit. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1). The requirements established in a preconstruction PSD or nonattainment NSR permit become applicable requirements that must be included in a source's title V permit.

Under section 505(a) of the Act, 42 U.S.C. § 7661d(a), and the relevant implementing regulations (40 C.F.R. § 70.8(a)), states are required to submit each proposed title V operating permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements under title V. 40 C.F.R. § 70.8(c). If EPA does not object to a permit on its own initiative, section 505(b)(2) of the Act provides that any person may petition the Administrator, within 60 days of expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2), *see also* 40 C.F.R. § 70.8(d). The petition must "be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." Section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2). In response to such a petition, the CAA requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2). S*ee also* 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2003). Under section 505(b)(2), the burden is on the petitioner to make the required demonstration to EPA. *Sierra Club v. Johnson*, 541 F.3d 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677-678 (7th Cir. 2008); *Sierra Club v. EPA*, 557 F.3d 401, 406 (6th Cir. 2009) (discussing the burden of proof in title V petitions); *see also NYPIRG*, 321 F.3d at 333 n.11. If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 C.F.R. §§ 70.7(g)(4) and (5)(i) – (ii) and 70.8(d).

Where a petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on a permitting authority's alleged failure to comply with the requirements of its approved PSD program (as with other allegations of inconsistency with the Act) the burden is on the petitioners to demonstrate that the permitting decision was not in compliance with the requirements of the Act, including the requirements of the SIP. Such requirements, as EPA has explained in describing its authority to oversee the implementation of the PSD program in states with approved programs, include the requirements that the permitting authority (1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; and (3) describe the determinations in enforceable terms. *See, e.g.*, 68 Fed. Reg. 9,892, 9,894-9,895 (March 3, 2003); 63 Fed. Reg. 13,795, 13,796-13,797 (March 23, 1998). EPA has approved the PSD programs into the SIPs of most states, including Wisconsin. *See, e.g.*, 64 Fed. Reg. 28,745 (May 27, 1999). In reviewing a petition to object to a title V permit raising concerns regarding a state's PSD permitting decision, EPA generally will look to see whether the petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary. *See, e.g., In re East Kentucky Power Cooperative, Inc.* (Hugh L. Spurlock Generating Station) Petition No. IV-2006-4 (Order on Petition) (August 30, 2007); *In re Pacific Coast Building Products, Inc.* (Order on Petition) (December 10, 1999); *In re Roosevelt Regional Landfill Regional Disposal Company* (Order on Petition) (May 4, 1999).

BACKGROUND

Columbia submitted to WDNR an application to renew its title V permit on October 17, 2007. WDNR provided the public notice of the draft title V permit on April 28, 2008 and proposed the title V renewal permit on July 9, 2008. During the public comment period, WDNR received comments on the draft permit, including comments from the Petitioner. EPA did not object to the permit. WDNR issued the final permit on September 2, 2008.

October 23, 2008 was the deadline, under the statutory timeframe in section 505(b)(2) of the Act, to file a petition requesting that EPA object to the issuance of the final Columbia permit. The Petitioner submitted its petition to object to the issuance of the Columbia permit to EPA on September 3, 2008. Accordingly, EPA finds that Petitioner timely filed this petition.

ISSUES RAISED BY THE PETITIONER

I. Prior PSD Applicability Determinations

The Petitioner states that every title V permit must assure compliance by the source with all applicable requirements. Petition at 2, citing section 504(a) of the CAA; 40 C.F.R. § 70.1, Wis. Stat § 285.64(1); and Wis. Admin. Code § NR 407.09(4)(b). Applicable requirements include SIP requirements, including the requirement to obtain a PSD preconstruction permit and apply the best available control technology (BACT). Petition at 2, citing 40 C.F.R. § 70.2; Wis. Stat. § 285.64(1); Wis. Admin. Code § NR 400.02(26); and *In re Monroe Electric Generating Plan, Entergy Louisiana, Inc.*, Petition No. 6-99-2 (June 11, 1999). The Petitioner further asserts that, if the facility is not in compliance with all applicable requirements at the time of permit issuance, the permit also must contain an enforceable schedule to bring the facility into compliance. Petition at 3, quoting *In the Matter of Onyx Environmental Services*, Petition No. V-2005-1 at 6-7 (February 1, 2006). The Petitioner concludes that the Administrator must object to the Columbia permit because, among other things, it omits applicable PSD requirements and a schedule of compliance to ensure compliance with applicable PSD requirements.

The Petitioner claims that PSD is an applicable requirement for the Colombia plant because, in 2006, WPL, the owners and operators of the facility, commenced construction of a project to replace the economizer, final superheater, and related components on Unit 1. According to the Petitioner, WPL estimated in its application to the Public Service Commission of Wisconsin (PSCW) that the cost of the project would be $18.9 million. Petition at 3. The Petitioner alleges that both WPL's application to the PSCW and the PSCW's response to the application identify the need to regain lost operating time as the purpose for the project. Petition at 4. The Petitioner asserts that WDNR concurred that the purpose of the project was to regain lost operating time attributable to the economizer and superheater sections of the boiler. *Id.* Based upon the WDNR analysis of the company's data, the Petitioner alleges that the permittee expects Unit 1 to regain 35.075 hours annually as a result of the project. The Petitioner asserts that, multiplied by the assumed emission rate, this would result in a 61 ton per year increase in sulfur dioxide (SO_2), an increase that exceeds the threshold for a "major modification." Petition at 4-5. However, the Petitioner states that WPL's calculations result in an increase of only 39 tons per year. Petition at 6, citing August 30, 2005 letter from Steve Jackson, WPL, to Steve Dunn, WDNR (Jackson letter). The Petitioner alleges that this conclusion is based on an impermissible interpretation of law "whereby a projected significant increase can be ignored and, instead, a facility can use confirmed-actual emissions to reevaluate emission increases after the project." Petition at 6. The Petitioner concludes that this is an erroneous interpretation of law, and, thus, the Administrator must object to the permit. *Id.*

A. The Economizer/Superheater Project on Unit 1

The Petitioner provides a summary of the PSD program and its history, and claims that the PSD program requirements, including permitting, BACT, and emission impact analysis, are "applicable requirements" for purposes of title V for each facility that undergoes a "major modification." Petition at 6-7, citing 42 U.S.C. §§ 7475(a), 7479; Wis. Admin. Code §§ NR 405.07, 405.09, 405.11, 405.13-405.15. The Petitioner asserts that the economizer/superheater replacement was a major modification because it was a physical change which, under the correct interpretation of the law, resulted in a projected significant increase in SO_2 emissions, even assuming all of WDNR's factual assumptions are true. Petition at 7-8.

Consistent with EPA's implementing regulations and the Act, Wisconsin's SIP, Wis. Admin. Code NR 405.02(21)(b)(2)(i) (2006) defined "major modification" as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any air contaminant subject to regulation under the act." Accordingly, for a major modification to occur there must be (1) a physical change and (2) a significant net emissions increase.

1. Physical Change

The Petitioner claims that the term "physical change" is very broad. According to Petitioner, Congress intended that "any physical change" trigger the PSD program, and intended the term to have an expansive meaning. Petition at 8, citing *New York v. EPA*, 443 F.3d 880, 885-87 (D.C. Cir 2006), *New York v. EPA*, 413 F.3d 3, 40-42 (D.C. cir. 2005); *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 909 (7^{th} Cir. 1990); September 9, 1988 memorandum "Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the Wisconsin Electric Power Company (WEPCO) Port Washington Life Extension Project 3." The Petitioner contends that the economizer/superheater replacement project was unquestionably a "physical change" because the components are large and took many weeks and millions of dollars to replace. Petition at 8-9.

Response

The air emissions at the Columbia plant are governed by the Wisconsin SIP-approved PSD program. The Wisconsin PSD program applicable at the time of WDNR's applicability determination and the 2006 project was approved by EPA on May 27, 1999 (64 Fed. Reg. 28745), and does not include later federal changes, "Reform," to the NSR major source regulations.

There is not a genuine dispute on the issue of whether the 2006 replacement of the economizer/superheater was a "physical change." WDNR does not suggest that WPL claimed that this project was not a physical change to the Columbia plant. Instead, WPL in effect acknowledged a physical change by seeking a regulatory exemption under Wisconsin's SIP from PSD construction permit requirements for the proposed change. The October 12, 2005 permit exemption letter from Roger Fritz, WDNR, to Steve Jackson, Alliant Energy (Fritz Letter) approved WPL's request to exempt the project from permitting requirements by allowing WPL to purportedly manage its emissions to avoid a significant net emissions increase.

2. Emission Increase

a. State failed to properly apply the applicable legal test

The Petitioner further alleges that the economizer/superheater replacement would result in a significant net emission increase under the correct legal test. The Petitioner asserts that, historically, to determine if a physical change results in a "significant net emissions increase" under the Wisconsin SIP, a source's actual emissions generally were compared to its potential to emit. Petition at 9, citing to Wis. Admin. Code §§ NR 405.02(1), (24)(a)1 (1988); *Puerto Rican Cement Co., Inc. v. U.S. EPA*, 889 F.2d 292, 296 (1st Cir. 1989) (some cites omitted). However, Petitioner asserts, an electric utility steam generating unit, like the Columbia facility at issue here, has the option to compare its historic "actual" emissions to its future projected emissions, based on EPA's 1992 rulemaking known as the "WEPCO Rule." Petition at 9-10, citing Wis. Admin. Code § NR 405.02(1)(d); *U.S. v. Murphy Oil USA*, 143 F. Supp.2d 1054, 1104. The Petitioner claims that the "actual-to-projected-actual" test is a projection of future emissions. Petition at 10. Petitioner states that, under the WEPCO Rule and EPA's December 31, 2002 rulemaking (67 Fed. Reg. 80186) in which EPA expanded the option to use the WEPCO Rule test to determine applicability for all types of facilities, an emission increase projection is based on the number of hours the unit is projected to operate in the future, multiplied by the emission rate. Petition at 10. The Petitioner suggests in a footnote that WPL underestimated the emissions from the project. Petition at 11, n. 3. The Petitioner states, however, that WPL's own figures show that the hourly emissions rate for Unit 1, which is based on the emission unit's operational capabilities following the change, is 3481.5 lb/hr (4985 MMBtu/hour*0.6984 lb SO_2/MMBtu). Petition at 11, citing Jackson letter, Attachment 1. The Petitioner calculates that, multiplied by the projected level of utilization attributable to the physical change, as required by the actual-to-projected-actual test, or 35.075 hours/year[1] in this case, the resulting projected increase in SO_2 is greater than 61 tons per year, which is a significant net emissions increase. Petition at 11. The Petitioner claims that this method of calculating a significant increase - a projection based upon regained operation hours multiplied by the hourly emission rate - is the same calculation EPA has used in numerous cases. Petition at 11, citing *United States v. Ohio Edison Co.*, 276 F. Supp.2d 829, 869-75 (S.D. Ohio 2003); *In re Tennessee Valley Authority*, 9E.A.D. 357, 439-52(EAB 2000).

The Petitioner alleges that WDNR did not determine PSD applicability based on the actual-to-projected-actual test. According to Petitioner, WDNR instead accepted WPL's interpretation of the law, which allowed WPL to ignore the projected significant increase, construct, and then determine PSD applicability based on confirmed post-project emissions. *Id.* Petitioner claims that WPL stated in a footnote to its 39 ton/year emission increase projection that "[p]lant operations will be managed to ensure Future Emissions are not exceeded above Past Actual emissions plus significant threshold." Petition at 11, quoting Jackson letter, Attachment 1, n.5. Petitioner asserts that this is an incorrect interpretation of law, as it noted in its comments on the draft permit. Petition at 11.

[1] Petitioner claims that this number is also too low. Petition at 11, n. 4.

The Petitioner further claims that WDNR did not respond substantively to its comments. Petitioner states that WDNR refused to revisit the prior interpretation of law, stating in its Response to Comments that "Sierra Club has not provided a sufficient basis for the Department to reexamine these previous exemptions or to require prevention of significant deterioration (PSD) permitting at this time." Petition at 12, quoting WDNR's Response to Comments at 2. The Petitioner states that WDNR's response is "wrong and insufficient," and, thus, the Administrator must object. The Petitioner alleges that the WEPCO Rule did not provide that a utility opting into the actual-to-projected-actual test "could ignore a projected significant increase and avoid PSD applicability based upon a promise to use actual-to-confirmed-actual post-project emissions to show no increase," but rather that the WEPCO Rule requires that a source first project that the change will not result in a significant increase, and then keep records to prevent "under-projecting." Petition at 12, citing 57 Fed. Reg. 32314, 32325 (July 21, 1992). The Petitioner claims that EPA expressly stated that the intent of the "backstop" recordkeeping and reporting provision was to "*confirm* the utility's initial projections rather than *annually revisiting* the issue of NSR applicability." *Id.* at 12. (Emphasis in original.) Petitioner further asserts that an "actual-to-confirmed-actual" test has been rejected by EPA and every court to consider it. Petition at 13, citing *U.S. v. SIGECO*, 2002 WL 1629817 (S.D. Ind. 2002); United States v. Cinergy Corp., 2005 U.S. Dist. LEXIS 28755; *United States v. Ohio Edison Co.*, 276 F. Supp.2d 829 (S.D. Ohio 2003); briefs and other documents filed by the United States in *U.S. v. Cinergy Corp.*, and *U.S. v. Duke Energy Corp.* The Petitioner concludes that WDNR's acceptance of WPL's "wait and see approach" for determining PSD applicability is unlawful, and that the Administrator must object to the permit. Petition at 14.

The Petitioner claims that WDNR's analysis is especially concerning because there is no explanation for WPL's projection of a 39 ton per year increase in SO_2. The Petitioner states that, although WPL asserts that it will "manage" the Columbia facility's operations to prevent an increase of SO_2 greater than 39 tons per year, WPL has not indicated that it will manage other pollutants, such as carbon monoxide, nitrogen oxides and particulate matter, for which WPL predicts emission increases. Petition at 14. The Petitioner claims that there are no post-combustion pollution controls for SO_2 at the Columbia facility Unit 1 and emissions for all pollutants are directly correlated to total hours of operation. Petition at 14, citing Jackson letter, Attachment 1. The Petitioner states that WPL's assertion that it will attempt to "manage" emissions post-project to limit increases in SO_2 conflicts with its projection of increases for the other pollutants, and concludes that this incongruity reinforces why EPA should not countenance WDNR's and WPL's reliance on the "actual-to-confirmed-actual" for SO_2. Petition at 14.

Response

EPA grants the petition on this issue and finds that WDNR misapplied the regulatory standard for determining whether the replacement of the economizer/superheater in 2006 resulted in a significant net emission increase. As discussed below, we further conclude the WDNR improperly allowed the facility to rely on a post-change emission level that was not consistent with "normal source operations" and that WDNR improperly allowed the source to rely upon certain exceptions noted below.

WDNR based its decision that the PSD requirements were not applicable to the Columbia plant on a misapplication of the regulatory standard for determining whether there was a significant emissions increase, and as a result improperly considered whether there was a significant net emissions increase. Under the applicable SIP provisions, a determination of whether a project results in a significant emissions increase is examined by comparing pre-change actual emissions[2] with a projection of post change emissions. As Petitioner does not dispute the calculation of pre-change emissions, the gravamen of Petitioner's argument is that WDNR used an improper legal standard to measure the post-project emissions from the replacement of the economizer/superheater in 2006. Petition at 2.

The then-applicable Wisconsin SIP provision for projecting actual emissions of electric utility facilities after a physical change is set forth in Wis. Admin. Code NR 405.02(1)(d)(2006). That provision states the following:

> For an electric utility steam generating unit, other than a new unit or the replacement of an existing unit, actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the department, on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the department if the department determines such a period to be more representative of normal source post-change operations.

NR 405.02(1)(d)(2006).

WDNR seeks to justify its approach for assessing post-project emissions for the project in the October 12, 2005 permit exemption letter from Roger Fritz at WDNR to Steve Jackson. In this letter, WDNR stated that "as long as the facility would be operated in a way that would not result in a *significant net emissions increase*, the project would not be a major modification, and would not require a construction permit under ch. NR 405, Wis. Adm. Code." Fritz Letter at 2. WDNR further stated that "projected future emissions would be limited by the applicant for nitrogen oxides and sulfur dioxide to below the sum of past actual emissions plus the significance threshold". *Id.* at 2. Although the significance threshold for $S0_2$ was 40 tpy, and the facility in fact projected a 61 ton increase in $S0_2$ due to regained operating hours, WDNR explained that "the applicant would limit operations to keep emissions below this level for the five-year period following the project." *Id.* at 2. Based on this faulty analysis that ignored the projected post-project emissions, WDNR excluded the project from PSD.

As noted above, the applicable provision for computing post-change emissions requires

[2] "Actual emissions" were defined under the Wisconsin SIP, Wis. Admin. Code NR 405.02(1) (2006), as "the actual rate of emissions of a air contaminant from an emissions unit, as determined in accordance with paragraphs (a) through (d)." Wis. Admin. Code NR 405.02(1)(a) (2006) provides a method for calculating pre-project actual emissions. Under this regulation, actual emissions before a project "shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation."

that they be "representative actual annual emissions." Wis. Admin. Code NR 405.02(1)(d) (2006). Absent from WDNR's approach of permitting post-project emissions management as a way to avoid PSD, is an explanation of how providing for a period of five years in which a facility artificially limits its emissions, and monitors to stay below the significance threshold, is consistent with this requirement.

Indeed, the five years in which the facility has agreed informally to constrain it emissions and report post-change emissions data appears directed at aligning with the post project recordkeeping requirement in NR 405.02(1)(d) (2006); but this five year window does not by its terms establish a window in which, if a facility artificially constrains its emissions, it avoids NSR. Since this artificial emission limit could not be considered "representative actual annual emissions of the unit" following the physical change, WDNR used the wrong methodology for measuring post-project emission increases for an electric utility steam generating unit. Accordingly, WDNR misapplied its SIP standard by using an artificial emission limit rather than the "representative actual annual emissions of the unit" following the physical change. The use of this artificial emission standard was inconsistent with Wis. Admin. Code NR 405.02(1)(d)(2006).

WDNR's use of an improper standard for projecting actual emissions from the project change also prevented it from properly determining whether the physical change would result in significant net emission increase. Wis. Admin. Code NR 405.02(24)(a)(2006) defines a "net emissions increase" as "the amount by which the sum of the following exceeds zero: 1. Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source. 2. Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable." WDNR did not do a proper applicability determination because it misapplied the PSD standard for determining actual emissions from the proposed physical change. As a result, WDNR improperly concluded that the physical change did not result in a major modification that triggered PSD permitting requirements.

WDNR also improperly relied on certain minor source permitting exemptions to justify its permitting decision. More specifically, WDNR found two additional grounds for excluding the project in 2005 from PSD permit requirements under Wis. Adm. Code sections NR 406.04(4)(e) - Increase in hours of operation and NR 406.04(4)(h) - Other changes. Fritz Letter at 2 An "increase in hours of operation" is not considered a modification under Wis. Adm. Code NR 406.04((4)(e) (2006) if:

> 1. The increase is not prohibited by any permit, plan approval or special order applicable to the source.
>
> 2. The increase will not cause or exacerbate the violation of an ambient air quality standard or ambient air increment or violate an emission limit.

Further, Wis. Adm. Code NR 406.04(4)(h) (2006) provides an exemption for a "change" that meets all of the following conditions:

1. The change is not prohibited by any permit, plan approval or special order applicable to the source.

2. The change is exempt under sub. (1), or the increased emissions due to the change do not exceed the maximum theoretical emission levels specified in sub. (2) (b), (c), (cm), (d) and (f).

3. The change does not trigger a requirement under section 111 or 112 of the Act, 42 U.S.C. § 7411 or 7412.

By the terms of Wis. Adm. Code NR 406.04, these exemptions are not applicable where the project constitutes a major modification. *See* Wis. Adm. Code NR 406.04 ("This section does not provide an exemption from construction permit requirements for a source that is required to obtain a permit under ch. NR 405"). Since WDNR has failed to show that the project was not a major modification under Wis. Adm. Code NR 405 (21) (2005) these exemptions do not apply.[3] WDNR does not offer a reasoned analysis sufficient to justify its PSD permitting decision. WDNR has simply misapplied its standard for determining the applicability of its SIP-approved PSD permit requirements.

WDNR must reevaluate the physical change in light of the correct PSD standards for determining actual emissions from the physical change at an electric utility steam generating unit. The WDNR must also do a proper applicability determination based on the correct post-project emissions standard, and clearly explain its analysis in the permit record. If WDNR concludes that the physical change, in fact, resulted in a significant net emissions increase for SO_2, WDNR must require WPL to obtain a PSD permit for the modification and will have to make appropriate changes to the source's title V permit and the permit record.

Further, EPA finds that WDNR failed to adequately respond to significant comments concerning whether PSD was triggered by the 2006 physical change. EPA has concluded that WDNR used the incorrect standard to determine PSD applicability. WDNR must reexamine its decision in light of the correct standard under its PSD regulations as discussed above and make appropriate changes to its permit and permit record. The failure of WDNR to respond to comments may have resulted in a flaw in the permit regarding PSD requirements.

b. State must address factual allegations regarding underestimation of post-change actual emissions

The Petitioner alleges that, in addition to WDNR's erroneous legal interpretation of the WEPCO Rule, WDNR also ignored evidence that the Petitioner supplied in its public comments regarding the estimate of the emissions increases attributable to the economizer/superheater project. Petition at 14, citing Sierra Club comments at 14-18. Petitioner states that WPL projected and WDNR accepted future emissions based on the emission rate multiplied by the maximum heat rate and the regained hours of operation. Petition at 15, citing Jackson letter,

[3] While there is a PSD exemption related to an increase in hours of operation or production rate this exemption does not apply if it was caused or was enabled by an independent physical change. *See, Environmental Defense v. Duke Energy Corp.*, 549 U.S. 561, 580.

ED_001598_00010204

Attachment 1. The Petitioner alleges that a review of data posted on EPA's Acid Rain Database from the Columbia continuous emissions monitor (CEM) for January 2003 through December 2004 shows that the average hourly heat input for that period was 5,357.7 MMBtu/hour, rather than 4,985 MMBtu/hour, as WPL had represented. Petition at 15, citing Sierra Club comments at 16. The Petitioner asserts that WDNR responded to the comment by stating that "Sierra Club has not provided a sufficient basis for the Department to reexamine these previous exemptions..." to the PSD permitting requirements. Petition at 16, quoting WDNR Response to Comments at 2. Petitioner asserts that a meaningful response to comments requires more, and that WDNR cannot refuse to look at data. Petition at 15. Further, Petitioner alleges that the exemption determination was not publicly noticed, and the public was given no opportunity to comment on it. Petition at 15-16. Petitioner asserts that WDNR's refusal during the title V permitting process to reexamine a determination it made without notice and comment would negate the opportunity for notice and comment on title V permits. Petition at 16. The Petitioner claims that, if allowed by EPA, this practice would invite WDNR to make "off-permit determinations," then refuse to reexamine them during the title V permit process. *Id.* The Petitioner concludes that EPA must object and require that WDNR provide a meaningful response to the Sierra Club's comments. The Petitioner further claims that the Administrator must object because the facts show that the CEMs data demonstrates that the average heat rate for Columbia Unit 1 is much higher than assumed by WDNR. *Id.*

The Petitioner further alleges that WPL's projected increase in hours of operation attributable to the economizer/superheater replacement project for purposes of PSD permitting was "vastly different than the number of hours WPL told the PSCW when attempting to justify the economic benefit of the modification." Petition at 16, citing Sierra Club comments at 16-17. The Petitioner states that "WPL told the PSCW that it suffered 3 tube failures in 2003 and 2 tube failures in 2004, and that the average tube failure forced outage lasted 7515 hours." Petition at 16, citing WPL's application to the PSCW at 11.[4] The Petitioner asserts that this data would suggest to the PSCW that the project would allow the unit to regain 188.75 hours annually, rather than the 30.075 reported to WDNR. Petition at 16. Petitioner further states that publicly available information from the Generation Availability Data System also indicates that WPL's 30.075 hours/year representation omitted an outage in May 2004. Petition at 16, citing Sierra Club comments at 17.

The Petitioner claims that WDNR's response to these comments was to say that WDNR "did not have 'a sufficient basis' to reexamine its prior exemption determination." Petition at 16. The Petitioner concludes that WDNR is required to provide a meaningful response to these comments. Petition at 16-17, citing *In re Midwest Generation, LLC, Waukegan Generation Station*, Petition No. V-2004-5 (September 22, 2005) (*Midwest Generation - Waukegan*); *In re Consolidated Edison Co. Hudson Ave. Gen. Station*, Petition No. II-2002-10 (September 20, 2003).

The Petitioner claims further that the Sierra Club comments showed that, if the pre-project baseline emissions were calculated for the 24 months immediately preceding the economizer/superheater replacement project, as the Petitioner asserts the Wisconsin SIP presumes, the number of regained hours of operation from the project would be 167.50 rather

[4] EPA believes the proper cite to the PSCW application should be to page 12.

than 30.075 hours. Petition at 17, citing Sierra Club comments at 17-18; Wis. Admin. Code NR 405.02(1)(a) (2004). The Petitioner alleges that WDNR, again, refused to reconsider its "prior off-permit non-applicability determination." Petition at 17. The Petitioner claims that this response, which "was effectively a refusal to consider the comment," is insufficient and that the Administrator must object. *Id.*

The Petitioner alleges that a title V permit "must assure[] compliance by the source with all applicable requirements." Petition at 17, quoting section 504(a) of the CAA. .(Some cites omitted.) The Petitioner further asserts that "applicable requirements" include "requirements contained in preconstruction permits and the requirement to obtain preconstruction permits, comply with BACT, and undertake air impact analysis." Petition at 17, citing 40 C.F.R. § 70.2; Wis. Stat. § 285.64(1); Wis. Admin. Code § NR 400.02(26). The Petitioner asserts that PSD requirements are applicable requirements for Columbia Unit 1, and WDNR's failure to assure compliance with PSD was based on erroneous data. Petitioner further claims that WDNR's analysis assumed an erroneous heat input for Unit 1, as well as underestimating the regained hours of operation attributable to the economizer/superheater replacement project. Petition at 17-18. The Petitioner claims that the permit's failure to assure compliance with PSD requirements results in unreviewed emission increases and a failure to ensure BACT emission limits are met, and concludes that the Administrator must object. Petition at 18.

Response

EPA finds that WDNR failed to adequately respond to significant comments concerning whether PSD was triggered by the 2006 physical change. The failure of WDNR to respond to comments may have resulted in a flaw in the permit regarding PSD requirements.

In its reevaluation, WDNR must consider and address Petitioner's assertions regarding underestimated emissions increases attributable to the project. For example, WDNR should address and resolve Petitioner's assertion of an apparent conflict related to calculations of the hourly heat input and the estimate of regained hours of operation due to the physical change.

II. Compliance Schedule

The Petitioner asserts that every title V permit "must disclose all applicable requirements and any violations at the facility." Petition at 18, citing section 503(b) of the CAA; 40 C.F.R. § 70.5(c)(4)(i), (5), (8); Wis. Admin. Code § NR 407.05(4)(h). The Petitioner further claims that, for applicable requirements for which the source is not in compliance at the time of permit issuance, the source's application must provide a narrative description of how the source intends to come into compliance with the requirements. Petition at 18, citing section 503(b) of the CAA; 40 C.F.R. § 70.5(c)(8)-(9); Wis. Admin. Code § NR 407.05(4)(h)2.c.; Midwest Generation - Waukegan at 4. The Petitioner states that the application must propose a compliance schedule for any applicable requirement with which the source is not in compliance. Petition at 18, citing 40 C.F.R. § 70.5(c)(8)(iii); Wis. Admin. Code § NR 407.05(4)(h)2.c. The Petitioner further claims that, if any statement in the application was incorrect, or if the application omits relevant facts, including the fact that a facility is not in compliance, the applicant has an ongoing duty to supplement and correct the application. Petition at 18, citing 40 C.F.R. § 70.5(b); Wis. Admin.

Code § NR 407.05(9). The Petitioner states that the final title V permit must contain a compliance schedule for any requirements with which the facility is not in compliance at the time of permit issuance. Petition at 18, citing section 504(a) of the CAA; 40 C.F.R. § 70.6(a), (c).

The Petitioner quotes at length from its comments on the draft permit, in which it set out data from the "most recent" excess emission reports which, Petitioner alleges, confirm that Columbia has "unaddressed, continuing opacity violations" from 2007 and 2008. Petition at 18-19. The Petitioner claims that it had attached to its comments the excess emissions reports, "signed by the company attesting to the accuracy, showing these ongoing violations." Petition at 19, citing to Columbia's excess emission report for opacity. The Petitioner alleges that WDNR agreed that there were violations at Columbia, but that it refused to impose a compliance schedule because it believed that "the duration of the exceedance is not significant enough to warrant a compliance plant [sic] in the current permit renewal;" based upon a guidance document from EPA regarding enforcement actions for high priority violations. Petition at 19-20, quoting WDNR Response to Comments at 2-3. The Petitioner claims that this was not a case in which WDNR determined that the excess emission reports were insufficient to demonstrate non-compliance, or where the Petitioner is asking the State or EPA to made a finding of violation where the "violations are contested by both the permitting authority and the source." Petition at 20 (cites omitted). Rather, Petitioner asserts, WDNR determined that there were violations at Columbia but nevertheless relied upon EPA guidance, *The Timely and Appropriate (T&A) Enforcement Response to High Priority Violations (HPVs)* Figure 4-4 (OECA June 23, 1995) (HPV Guidance), to determine that, despite the violations, no compliance schedule was required. Petition at 20. The Petitioner claims that the result of WDNR's interpretation is "to confine the requirement of a compliance schedule in 42 U.S.C. § 7661c(a) and 40 C.F.R. § 70.5(c)(8)(iii) to High Priority violations under EPA Guidance." Petition at 20. The Petitioner states that WDNR "suggests that only violations meeting the definition of a High Priority violation or HPV under EPA Guidance" require a compliance schedule in the Part 70 permit. Petition at 20, citing WDNR Response to Comments at 2. Petitioner asserts that WDNR misinterprets the law; neither title V nor Part 70 conditions the requirement of a compliance schedule on a "significance" threshold. Petition at 20. The Petitioner claims that, based on the plain language of section 504(a) of the CAA, as well as 40 C.F.R. § 70.6(a)(1), "a schedule of compliance is required in each permit." Petition at 21. The Petitioner concludes that, since WDNR agrees that Columbia is not complying with opacity limits at all times, a compliance schedule is mandatory, and WDNR's failure to include one in the permit requires that the Administrator object. Petition at 22.

The Petitioner asserts that the Administrator has objected previously, based on a petition that raised a similar issue. The Petitioner states that Sierra Club had petitioned the Administrator to object to a title V permit, issued to the TVA Gallatin Power Plant, which allowed the facility to rely on emission reports to certifying compliance with opacity limits, despite the fact that the emission reports showed violations of the opacity standard up to 2% of operating time. According to the Petitioner, in that case, a state regulation exempted facilities violating the opacity limit less than 2% of the time from immediate enforcement actions, and, based on that regulation, the title V permit allowed reports showing violations up to 2% of the time to be "prima facie evidence of compliance." Petition at 22, citing *In re TVA Gallatin Power Plant,* Petition No. IV-2003-4 (July 29, 2004) (*TVA Gallatin*) at 4-8. The Petitioner claims that EPA objected to the permit because the exception for up to 2% of operating time contradicted the applicable standard in the SIP. *Id.* The Petitioner concludes that, although EPA's objection in the *TVA Gallatin* petition was based on 40 C.F.R. § 70.6(c)(1), the holding applies here: exemptions from opacity limits based on enforcement policies that are not included in the approved SIP are not a lawful basis for omitting applicable Part 70 requirements. *Id.*

The Petitioner further claims that the HPV criteria to which WDNR cited were not intended for title V permitting, and asserts that violations that do not constitute HPVs are not considered compliance with the law. *Id.* The Petitioner states that the HPV Guidance is intended to "'prioritize violations for enforcement purposes,' and not to redefine what constitutes a violation." Petition at 22-23, quoting HPV Guidance at 1-1. The Petitioner claims that the HPV Guidance emphasizes that it should not be read as excusing violations. Petition at 23, citing HPV Guidance at 1-1. The Petitioner states that the HPV Guidance directs that it "cannot be used to establish new standards or limits, are not binding on any party, and cannot be relied upon to create any rights enforceable by any party." Petition at 23, quoting HPV Guidance at A-1. The Petitioner concludes that the HPV Guidance does not define a violation, but prioritizes which violations will receive the most attention when spending limited civil and criminal enforcement resources. Petition at 23. The Petitioner asserts that WDNR should be "well aware" that the guidance does not re-write the regulations that establish standards. The Petitioner quotes extensively from a September 6, 2005 letter, in which the Wisconsin Attorney General stated "there is no 'minor violations' exception in the law, and that violations of the law, no matter how seemingly 'minor' in effect, do and should have enforcement consequences commensurate with those violations." Petition at 23-24, quoting September 6, 2005 Wisconsin Attorney General letter. The Petitioner claims that WDNR's "decision to sanction excess opacity emissions" conflicts with the CAA, Part 70, and EPA's prior decisions, as well as the State Attorney General's interpretation of the law and guidance. The Petitioner concludes the Administrator must object to the Columbia title V permit and require WDNR to reissue the permit with a compliance schedule that brings the plant into compliance with visible emission limits, consistent with 40 C.F.R. § 70.5(c)(8).

Response

EPA's regulations require a compliance schedule for "sources that are not in compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.5(c)(8)(iii)(C); see also 40 C.F.R. § 70.6(c)(3). EPA finds that Petitioner has not demonstrated noncompliance at the time of permit issuance necessitating a compliance schedule. Although Petitioner submitted opacity reports showing emissions in excess of the opacity standard, Petitioner's reference to these reports does not demonstrate that the source's exceedances of the opacity standard were violations, or that the source was in non-compliance at the time of permit issuance necessitating a compliance schedule. EPA notes that not all exceedances necessarily constitute violations of the opacity standards. The Wisconsin SIP contains certain exceptions from the opacity standard. See NR 431.05. Further, WDNR reviewed these emission reports and determined the exceedances were "not significant enough to warrant a compliance plan in the current permit renewal." Response to comments at 2.

Contrary to Petitioner's assertion, it is not clear from WDNR's response to comment that the State actually found that the source was in violation of opacity requirements at the time of permit issuance. The Petitioner makes much of the fact that the State determined that the exceedances would not trigger the high priority enforcement policy. EPA does not believe that the State's discussion of the high priority enforcement policy constituted a finding that the source was in violation of opacity requirements at the time of permit issuance. EPA notes that if a permitting authority determines that a source is in violation of a requirement at the time of permit issuance, it would not be appropriate for the permitting authority to simply refer to an enforcement policy to determine that no compliance schedule is necessary. But here the State did not expressly find violations at the of permit issuance necessitating a compliance schedule. See *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670 (7th Cir. 2008) (upholding EPA's decisions denying petitions to object to several title V permits issued by the Illinois Environmental Protection Agency to Midwest Generation, and finding that, in light of the strict time lines for title V permit processing and review, the complementary enforcement authorities under the Act, the fact that the sources had certified compliance, and the State's review of the data, it was reasonable for EPA to determine that petitioners had not made the requisite demonstration under CAA section 505(b)(2) that the permit was not in compliance with the Act).

The Petitioner also argues that:

> The Administrator has objected previously based on a petition raising a similar issue. *In re TVA Gallatin Power Plant*, Petition IV-2003-4, Order at 4- 8 (EPA Adm'r July 29,2004). In the *TVA Gallatin* case, Sierra Club petitioned the Administrator to object to a Title V permit that allowed a facility to rely on emission reports to certify compliance with opacity limits despite the fact that the emission reports showed violations of the opacity standard up to 2% of operating time. *Id.* A state regulation exempted facilities violating the opacity limit less than 2% of the time from immediate enforcement actions and, based on this regulation, the title V permit allowed reports showing violations up to 2% of the time to be "prima facia evidence of compliance." *Id.* However, because the exception for up to 2% of operating time contradicted the applicable standard in the state implementation plan, EPA objected. *Id.* Although EPA's objection in the *TVA Gallatin* case was based on 40 C.F.R. § 70.6(c)(1), the holding is equally applicable here-exemptions from opacity limits based on enforcement policies that are not included in the approved implementation plan are not a lawful basis for omitting applicable Part 70 requirements.

Petition at 22. Plainly, the *TVA Gallatin* matter has little relevance here. For example, unlike *TVA Gallatin*, the current petition does not involve an allegation that the permit terms contradict the applicable requirements regarding opacity. In the present matter, the title V renewal permit does not improperly excuse or exempt opacity exceedances up to 2% of the time or allow such to be "prima facia evidence of compliance." *Id.*

For the reasons noted above, I deny the Petition on this issue.

III. Part 2 Application for Case-by-Case MACT for Industrial Boilers

The Petitioner claims that Columbia is a major source of hazardous air pollutants under section 112 of the Act, and that it contains an industrial boiler covered by 40 C.F.R. Part 63, subpart B, Table 1. Petition at 25, citing to Sierra Club comments at 27-28 The Petitioner contends that, because the Circuit Court of Appeals for the District of Columbia (D.C. Circuit) vacated the MACT for industrial boilers in *Natl. Res. Def. Council v. EPA*, 489 F.3d 1250 (D.C. Cir. 2007), industrial boilers are subject to the "MACT Hammer" provision of 42 U.S.C. § 7412(j). Petition at 25-26. Thus, the Petitioner reasons, the requirement to apply for a limit under section 112(j), Part 2 of the CAA applies to Columbia. Petition at 26, citing 40 C.F.R. § 63.52(e). The Petitioner states that it requested in its comments on the draft permit that WDNR "acknowledge that 112(j) and 40 C.F.R. §§ 63.50 - 63.56 are applicable requirements, and include a schedule of compliance requiring a MACT Part 2 application immediately, and a revised title V permit within 18 months to incorporate a case-by-case limit." Petition at 26, citing Sierra Club comments at 31-32 (additional cites omitted). The Petitioner claims that WDNR refused, saying that '[a]t this time there are no specific enforceable requirements that we can include in the operation permit, such as when an application under s. 112(j) needs to be submitted." Petition at 26, quoting WDNR Response to Comments at 3. The Petitioner asserts that WDNR is incorrect, that the requirement to apply for a limit under section 112(j) of the CAA applies to Columbia, and that WDNR must include it in the Columbia permit. Petition at 26.

The Petitioner asserts that the case-by-case MACT limit and the requirements to submit a Part 2 application and obtain a case-by-case MACT limit are applicable requirements, and that the Administrator must object because WDNR did not include either these applicable requirements or a schedule of compliance in the Columbia permit. Petition at 27. The Petitioner discusses at length why these requirements are "applicable requirements" under 40 C.F.R. § 70.2. *Id.*

The Petitioner claims that 40 C.F.R. § 63.52(e)(1) is an applicable requirement which provides that "[e]ach owner or operator who is required to submit to the permitting authority a Part 1 MACT application ... must also submit to the permitting authority a timely Part 2 MACT application for the same sources which meets the requirements of Sec. 63.53(b) ... *no later than the applicable date specified in Table 1 to the subpart* (emphasis added)." Petition at 27, quoting 40 C.F.R. § 63.52(e)(1). The Petitioner notes that WPL has submitted a Part 1 application for the Columbia facility. Petition at 27. The Petitioner states that, in its comments on the draft permit, the Sierra Club requested that WDNR acknowledge that 112(j) and 40 C.F.R. §§ 63.50-63.56 are applicable requirements, include a schedule of compliance requiring a MACT Part 2 application immediately, and revise the Columbia title V permit within 18 months to incorporate a case-by-case limit. The Petitioner asserts that, according to table 1 under 40 C.F.R. § 63.53(b), the deadline to submit a Part 2 application was April 28, 2004. *Id.* The Petitioner concludes that the Administrator must object because case-by-case MACT limits and the requirement to submit a Part 2 application are applicable requirements that WDNR did not include in the permit. Petition at 27-28. The Petitioner further states that Part 70 requires that each permit contain a compliance schedule consistent with 40 C.F.R. § 70.5(c)(8). Petition at 28, citing 40 C.F.R. §§ 70.5(c)(8), 70.6(c)(3). The Petitioner asserts that the Administrator must also object because the Columbia permit does not contain a schedule of compliance to bring the facility into compliance with both the obligation to submit a Part 2 application and the future obligation to comply with a case-by-case section 112(j) limit that will become effective during the five-year permit term. Petition at 28.

Response

In its July 9, 2008, Response to Comments, WDNR stated:

> Boilers and process heaters at major sources of hazardous air pollutants were subject to regulation under 40 CFR 63 Subpart DDDDD, which was vacated by the D.C. Circuit Court of Appeals (6/8/2007). The Department promulgated a standard at ch. NR 462, Wis. Adm. Code, which is equivalent to the vacated boiler MACT at 40 CFR 63 Subpart DDDDD. The state rule was stayed by emergency order AM-38-07E and order AM-37-07. The absence of the EPA standard may trigger the requirements of s. 112(j)(5) of the Clean Air Act which generally requires affected facilities to submit a permit application for a case-by case MACT determination under 40 CFR 63.52. The Department is waiting for specific guidance from EPA on what must be done when a promulgated standard is vacated by the courts. At this time there are no specific enforceable requirements that we can include in the operation permit, such as when an application under s. 112(j) needs to be submitted. Once a complete application has been received, the Department may revise the permit under s. NR 407.14, Wis. Adm. Code, to make the case-by-case MACT determination. A footnote was added to the final permit addressing the applicability of s. 112(j).

WDNR Response to Comments at 3.

WDNR added a footnote to the final permit for Columbia regarding 112(j) which states:

> The Department may revise this section under s. NR 407.14, Wis. Adm. Code, to address additional requirements for hazardous air pollutant emissions as required under section 112(j) of the Clean Air Act [42 U.S.C. 7412(j)]. Under s. 112(j)(2), an affected facility is required to submit a permit application if EPA fails to promulgate a standard for a source category (industrial boiler).

Columbia permit at 5.

Subsequent to responding to the Petitioner's comments on Columbia permit P20 on July 9, 2008, WDNR requested a 112(j) application from Columbia. On November 11, 2008, WDNR notified potentially subject sources, including Columbia, via email, of their 112(j) obligations. In the message, WDNR stated, "[o]ne interpretation is that an application is due no later than 18 months after the court vacatur of the EPA standard for boilers and process heaters (i.e. due 1/27/2009)." WDNR received Columbia's 112(j) Part 1 application on January 26, 2009, and its Part 2 application 60 days later, on March 26, 2009.

The Petitioner claims that Part 70 requires that each permit contain a compliance schedule consistent with 40 C.F.R. § 70.5(c)(8). The Petitioner asserts that the Administrator must object because the Columbia permit does not contain a schedule of compliance to bring the facility into compliance with both the obligation to submit a Part 2 application and the obligation to comply with a case-by-case section 112(j) limit that will become effective in the future. Even assuming that Petitioner's view of Columbia's obligation to submit a Part 2 application is correct, because Columbia has already submitted its Part 2 application, Petitioner's claim with respect to this issue is moot. With respect to Petitioner's claim that the permit's schedule of compliance must address the future obligation to comply with a case-by-case section 112(j) limit, EPA notes that WDNR would incorporate a 112(j) limit through a title V permit amendment and it is possible that compliance with any such limit will not be required until after the current permit term. Thus EPA denies the claim that the title V permit that is the subject of this petition was required to address the 112(j) limit.

For the reasons discussed above, I deny the petition on this issue.

CONCLUSION

For the reasons set forth above, and pursuant to section 505(b)(2) of the Clean Air Act, I am granting in part and denying in part the petition filed by David Bender on behalf of the Sierra Club. Because this permit has been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures in 40 C.F.R. §§ 70.7(g)(4) or (5)(i) and (ii), and 70.8(d). WDNR shall have 90 days from receipt of this Order to resolve the objections identified above and to terminate, modify, or revoke and reissue the Columbia title V renewal permit accordingly.

Dated: 10/9/09

Lisa P. Jackson
Administrator

To: Kornylak, Vera S.[Kornylak.Vera@epa.gov]; Jones, Rhea[Jones.Rhea@epa.gov]; Lorang, Phil[Lorang.Phil@epa.gov]; Beaver, Melinda[Beaver.Melinda@epa.gov]
Cc: Koerber, Mike[Koerber.Mike@epa.gov]
From: Wood, Anna
Sent: Mon 6/5/2017 11:46:33 PM
Subject: Fwd: EPA Regulatory Reform
051517-StateofTexasAG-CommentLetter-combined.pdf
ATT00001.htm

Fyi

Sent from my iPhone

Begin forwarded message:

From: "Stenger, Wren" <stenger.wren@epa.gov>
To: "Wood, Anna" <Wood.Anna@epa.gov>
Subject: FW: EPA Regulatory Reform

Anna, don't hit print.

The attachment is over 100 pages. Go to Attachment 2 and you will find the TCEQ list of litigation.
The chart of TX/EPA litigation is attachment 2 in the attached document.

KEN PAXTON
ATTORNEY GENERAL OF TEXAS

May 15, 2017

Honorable Scott Pruitt, Administrator
U.S. Environmental Protection Agency
Office of the Administrator, MC 1101A
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

via regulations.gov

Re: Docket ID No. EPA-HQ-OA-2017-0190, Comments from Texas concerning stay of imminent regulatory deadlines for existing regulations currently subject to litigation and abatement of such litigation pending review of each rule.

Dear Administrator Pruitt;

We write in response to the Environmental Protection Agency's (EPA's) request for comment concerning the agency's internal review and evaluation of existing regulations. *See* 82 Fed. Reg. 17,793 (Apr. 13, 2017). We ask that the EPA Regulatory Reform Task Force consider these comments regarding EPA regulations currently subject to judicial review. The goals stated in Executive Order 13777, Enforcing the Regulatory Reform Agenda (Feb. 24, 2017), if achieved, will help return our country to an era of less burdensome federal regulation and greater cooperation between the federal government and states in environmental regulation.

<u>Cooperative Federalism Principles are Embodied in Environmental Law.</u>

Cooperative federalism is an important principle in our country. This is because "the role of the States as laboratories for devising solutions to difficult legal problems" is long recognized. *Oregon v. Ice*, 555 U.S. 160, 171 (2009); *see United States v. Lopez*, 514 U.S. 549, 581 (1995) (Kennedy, J., concurring) ("[T]he States may perform their role as laboratories for experimentation to devise various solutions where the best solution is far from clear."); *New State Ice Co. v. Liebmann*, 285 U.S. 262, 311 (1932) (Brandeis, J., dissenting) ("It is one of the happy incidents of the federal system that a single courageous State may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country."). To this point, we recognize that deference to the States "allows local policies 'more sensitive to the diverse needs of a heterogeneous society,' permits 'innovation and experimentation,' enables greater citizen 'involvement in democratic processes,' and makes government 'more responsive by putting the States in competition for a mobile citizenry.'" *Bond v. United States*, 131 S. Ct. 2355, 2364 (2011) (quoting *Gregory v. Ashcroft*, 501 U.S. 452, 458 (1991)).

Therefore, when it comes to relations between the States and the federal government, the Supreme Court has admonished the importance of seeking the appropriate "federal balance." *Nat'l Fed'n of Indep. Bus. v. Sebelius ("NFIB")*, 132 S. Ct. 2566, 2659 (2012). The power to spend money, for example, "without concern for the federal balance, has the potential to obliterate distinctions between national and local spheres of interest and power by permitting the Federal Government to set policy in the most sensitive areas of traditional state concern, areas which otherwise would lie outside its reach." *NFIB*, 132 S. Ct. at 2659. The same is true when the federal government exercises its regulatory power. For only if the States are able to experiment, so that we may learn lessons from our collective experiences, will the depth and breadth of the potential of our Union be fulfilled. [1]

Litigation and Regulation Enforcement Should be Suspended Pending Agency Reconsideration.

Unfortunately, as you are aware, the previous administration was unwilling to engage with most states, and took actions or issued rules ignoring the spirit of cooperative federalism embodied in the Clean Air Act and Clean Water Act. *See* 42 U.S.C. § 7401(a)(3), 33 U.S.C. § 1251(b). As a result, Texas and others, along with industry representatives, were routinely forced to seek judicial review of many of the EPA's actions. Enclosed at Attachment 2 is a list of pending actions in which Texas is still involved.

The issue statements and briefs filed in the list of pending actions articulate why each of the challenged rules or actions are arbitrary and capricious, not in accordance with the law, are unnecessary or ineffective, impose costs that exceed benefits, and otherwise create serious inconsistency with the initiatives described in Executive Order 13777. Enclosed at Attachments 3A and 3B are the petitions for review and statement of issues filed by Texas in each of the matters.[2] For the reasons discussed in the filings concerning each of the rules listed in Attachment 1, we request that each of those rulemakings be reconsidered and that any imminent regulatory deadlines be suspended pending your Agency's reconsideration.

Furthermore, although the Department of Justice has sought to abate many matters in litigation while the EPA revaluates each rule,[3] several matters identified in Attachment 1 are not abated, including the Cross State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 Fed. Reg. 74,504 (Oct. 26, 2016); *Texas v. EPA*, 16-1428; consolidated with *Wisconsin v. EPA*, 16-1406 (D.C. Cir.), and Air Quality Designations for the 2010 Sulfur Dioxide Primary National Ambient Air Quality Standard, 81 Fed. Reg. 89,870 (Dec. 13, 2016); *Texas v. EPA*, 17-60088 (5th Cir.); *Texas v. EPA*, 17-1053, consolidated with *Masias (Sierra Club) v. EPA*, 16-1314 (D.C. Cir.).

---

[1] This is the subject of a more comprehensive letter Texas and 18 other states previously addressed. Letter from Hon. Ken Paxton to Hon. Scott Pruitt, Mar. 7, 2017, at https://www.texasattorneygeneral.gov/files/epress/FINAL_Signed_Letter_to_EPA.pdf (also enclosed at Attachment 1).

[2] Because the Court of Appeals for the Fifth Circuit does not mandate the filing of issue statements, those issue statements are not included. Due to the voluminous nature of filed briefs, we refer the agency to the briefs in such cases rather than include them here.

[3] The abatement of litigation is consistent with Executive Order 13783, Promoting Energy Independence and Economic Growth (Mar. 28, 2017), and Executive Order 13777.

Each of these matters have looming briefing or motion deadlines. Rather than have Texas and other petitioners continue to incur legal expenses and costs to challenge regulations that should be reevaluated, EPA should direct the Department of Justice to abate these matters pending further review of each rule. Any imminent deadlines imposed by those rules should be suspended during agency review.

Abatement of the litigation will allow the EPA time to consider each rule, especially for those rules that form part of a larger, comprehensive framework of unnecessary, overlapping, and duplicative regulation promulgated by the prior administration targeting the same pollutants, goals, and programs of other rulemakings. Particular consideration should be paid to the comprehensive social, economic, and health effects of the entire network of rulemakings and whether rules impose duplicative burdens for negligible net benefits. Abatement will also permit the agency an opportunity to consult with parties in the litigation about revisions to particular rules that might resolve individual grievances.

We appreciate that your agency has many priorities and matters to which to attend and that this request will require substantial deliberation. However, in order to save everyone time and resources, please consider an immediate suspension of any and all active litigation and new regulatory enforcement while the EPA conducts its review and reconsideration of these matters.

We appreciate and thank you for your attention to this matter.

Sincerely yours,

Priscilla M. Hubenak
Chief, Environmental Protection Division
Office of the Attorney General of Texas

Attachments

cc: Ms. Sarah Rees, Director
Office of Regulatory Policy and Management
Office of Policy
Environmental Protection Agency
Mail Code 1803A
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

ATTACHMENT 1

KEN PAXTON
ATTORNEY GENERAL OF TEXAS

March 7, 2017

Hon. Scott Pruitt, Administrator
U.S. Environmental Protection Agency
Office of the Administrator, 1101A
1200 Pennsylvania Avenue, N.W.
Washington D.C. 20460

Re: Request to reexamine delegation of certain environmental regulation authority to the States in accordance with the express terms of the Clean Air and Water Acts; from State of Texas, from State of Alabama, from State of Arizona, from State of Arkansas, from State of Georgia, from State of Indiana, from State of Kansas, from State of Kentucky, from State of Louisiana, from State of Mississippi, from State of Missouri, from State of Montana, from State of Nebraska, from State of Nevada, from State of North Dakota, from State of Oklahoma, from State of South Carolina, from State of West Virginia, from State of Wyoming

Dear Administrator Pruitt:

We write to call your attention to the fact that the extensive regulation from the Environmental Protection Agency during the last decade is directly at odds with the express terms and structure of the Clean Air Act and Clean Water Act. We ask that as you assess the performance of your Agency, you do so with a keen eye toward compliance with these governing laws and not repugnance to them.

These federal laws acknowledge basic truths: that the primary regulators of the environment are the States and local governments. The Clean Air Act wastes no time making this point. The very first section states that "air pollution prevention . . . and air pollution control at its source is the primary responsibility of States and local governments." 42 U.S.C. § 7401(a)(3). The Clean Air Act then establishes a preferred method for the federal government to assist States and local governments: "to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs." *Id.* § 7401(b)(3). The Act's terms such as "encourage," "assist," and "promote" envision a collaborative arrangement.[1] As one court summarized,

[1] The Clean Water Act is based on a collaborative framework that is substantially similar to the cooperative arrangement underlying the Clear Air Act. *See, e.g.*, 33 U.S.C. § 1251(b) (providing that the policy of the Clear Water Act is to preserve the "primary responsibilities of States to prevent, reduce, and eliminate" water pollution).

"[t]he great flexibility accorded the states under the Clean Air Act is ... illustrated by the sharply contrasting, narrow role to be played by EPA." *Fla. Power & Light Co. v. Costle*, 650 F.2d 579, 587 (5th Cir. 1981).

The methods we have seen from the Agency as of late, however, are in direct conflict with the cooperative arrangement the Act establishes. The Agency has replaced "encourage" and "promote" with "command" and "commandeer." Take one recent example. Texas formulated a state implementation plan for Regional Haze. That plan imposed reasonable regulations on such things as power generators in the State to ensure air quality was sufficiently high to allow good visibility. The Agency rejected the State's plan, imposed a federal plan costing $2 billion without achieving any visibility changes, and tried to insulate itself by requiring Texas to challenge the rejection of its plan in the D.C. Circuit.

Unsurprisingly, the Fifth Circuit rejected the Agency's attempt to transfer venue and stayed the federal plan.[2] At that point, the Agency had the opportunity to return to using its authority under the Act—rather than acting on its own. Instead, the Agency imposed a renewed regional haze rule almost as bad as the first.[3] These actions show that the Agency ignored the efforts of the State, perhaps blinded by the belief that good results can only result from top down management by the federal government. Or worse, the prior Administration's agenda and policy goals drove the Agency's decision rather than the requirements of the statute.

The federal government must respect the clear terms of cooperative federal-state enactments. For example, federal agencies may not add conditions on the receipt of federal funds unless the terms are clearly stated in the controlling statute. *Arlington Cent. Sch. Dist. Bd. of Educ. v. Murphy*, 548 U.S. 291, 296 (2006). And federal agencies may not stray outside the boundaries of their statutory authority by relying on policy documents and other non-statutory materials. *See, e.g., Luminant Generation Co., LLC v. EPA*, 675 F.3d 917, 931 (5th Cir. 2012).

Similarly, the federal government may interpose itself between a State and its municipal subdivisions only if Congress provides a clear directive to do so. *Tennessee v. FEC*, 832 F.3d 597, 610 (6th Cir. 2016). From our perspective, the recent overreach by the Agency amounts to a striking departure from the Clean Air and Clean Water Acts. Respectfully, we ask that you consider the steps that the Agency may take to restore the principles of cooperative federalism embodied in these important statutes.

Sincerely yours,

---

[2] *Texas v. United States Envtl. Prot. Agency*, 829 F.3d 405 (5th Cir. 2016).

[3] 82 Fed. Reg. 3,078 (Jan. 10, 2017)

Ken Paxton
Attorney General of Texas

Stephen T. Marshall
Attorney General of Alabama

Mark Brnovich
Attorney General of Arizona

Leslie Rutledge
Attorney General of Arkansas

Christopher Carr
Attorney General of Georgia

Curtis T. Hill, Jr.
Attorney General of Indiana

Derek S. Schmidt
Attorney General of Kansas

Matt Bevin
Governor of Kentucky

Jeff Landry
Attorney General of Louisiana

Phil Bryant
Governor of Mississippi

John Hawley
Attorney General of Missouri

Tim Fox
Attorney General of Montana

Douglas Peterson
Attorney General of Nebraska

Adam Paul Laxalt
Attorney General of Nevada

Wayne Stenehjem
Attorney General of North Dakota

Mike Hunter
Attorney General of Oklahoma

Alan Wilson
Attorney General of South Carolina

Patrick Morrisey
Attorney General of West Virginia

Peter Michael
Attorney General of Wyoming

cc: Hon. Jeff Sessions, United States Attorney General

ATTACHMENT 2

PENDING EPA RULE CHALLENGES BY THE STATE OF TEXAS

RULE CHALLENGED	CAUSE NOS.	CURRENT STATUS	CASE ABATED?
Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 Fed. Reg. 74,504 (Oct. 26, 2016)	*Texas v. EPA*, 16-1428; consolidated with *Wisconsin v. EPA*, 16-1406 (D.C. Cir.)	On 12/20/16, the State of Texas filed its petition for review. The case is pending a briefing schedule. DOJ has NOT requested abatement of the case.	No.
Air Quality Designations for the 2010 Sulfur Dioxide Primary National Ambient Air Quality Standard, 81 Fed. Reg. 89,870 (Dec. 13, 2016)	*Texas v. EPA,* 17-60088 (5th Cir.) *Masias (Sierra Club) v. EPA*, 16-1314 (*Texas v. EPA*, 17-1053) (D.C. Cir.)	On 2/13/17, Texas filed its petitions for review in the 5th Circuit and the D.C. Circuit. Despite this matter affecting only Texas, on 3/24/17, the DOJ filed a motion to dismiss Texas' filing in the 5th Circuit and seeks to transfer the matter to the D.C. Circuit and combine it with a matter filed by the Sierra Club (16-1314). The motion to dismiss/transfer is being briefed. The DOJ has NOT requested abatement of the case, and the parties await a decision from the court.	No.
Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, 77 Fed. Reg. 33,642 (June 7, 2012)	*Texas v. EPA*, 12-1344, consolidated with *Utility Air Regulatory Group v. EPA,* 12-1342, (D.C. Cir.)	On 8/6/12, the State of Texas filed its petition for review. Final briefs have been filed and the matter is pending oral argument. The DOJ has NOT requested abatement of the case.	No.
[Dis]approval and Promulgation of Air Quality Implementation Plans; Texas; Interstate Transport of Air Pollution for the 2008 Ozone NAAQS, 81 Fed. Reg. 53,284 (Aug. 12, 2016)	*Texas v. EPA*, 16-60670 (5th Cir.)	On 10/11/16, the State of Texas filed its petition for review. On 3/2/17, Texas filed its opening brief. DOJ abatement request pending.	Pending motion.
Protection of Visibility: Amendments to Requirements for State Plans, 82 Fed. Reg. 3078 (Jan. 10, 2017)	*Texas v. EPA*, 17-1021 (D.C. Cir.)	On 1/18/17 (docketed on 1/23/17), the State of Texas filed its petition for review. The case is pending a briefing schedule. DOJ abatement request pending.	Pending motion.

PENDING EPA RULE CHALLENGES BY THE STATE OF TEXAS

RULE CHALLENGED	CAUSE NOS.	CURRENT STATUS	CASE ABATED?
Clean Water Rule: Definition of "Waters of the United States", 80 Fed. Reg. 37,054 (June 29, 2015)	*Texas v. EPA*, 3:15-cv-00162 (S.D. Tex.); *Texas v. EPA*, 15-60492 (5th Cir.) *In re: EPA Final Rule*, No. 15-3751 (6th Cir.) (consolidated matter includes 15-3853 (Texas) *National Assoc. of Manufacturers v. Dept. of Def., No. 16-299 (U.S.)*	On 6/29/15, Texas filed its complaint challenging the rule in the S.D. Tex. and on 7/16/15 Texas filed a petition for review in the 5th Circuit. The 5th Cir. matter was transferred with others to the 6th Cir. Industrial petitioners brought a jurisdictional question to the Supreme Court, which is pending. The rule has been stayed pending judicial review. A DOJ request to abate the proceeding in the Supreme Court was denied.	No—Court denied, but rule stayed by order of the Court.
Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824 (June 3, 2016)	*Texas v. EPA*, 16-1257, consolidated with *North Dakota, v. EPA*, 16-1242 (D.C. Cir.), and further consolidated with *American Petroleum Institute v. EPA*, 13-1108	On 7/28/16, the State of Texas filed its petition for review. The case is pending a briefing schedule. On 4/4/17, the EPA announced it was reconsidering this rule, 82 Fed. Reg. 16331. On 4/7/17, the DOJ requested abatement of the case, which remains pending.	DOJ requested on 4/7/17.
National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,292 (Oct. 26, 2015)	*Texas v. EPA*, 15-1494, consolidated with *Murray Energy Corp. v. EPA*, 15-1385 (D.C. Cir.)	On 12/23/15, the State of Texas filed its petition for review. Briefing is complete and oral arguments were scheduled. The DOJ requested abatement of the case, which the Court granted on 4/11/17.	Yes—granted 4/11/17.
State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy, and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown, and Malfunction, 80 Fed. Reg. 33,839 (June, 12, 2015)	*Texas v. EPA*, 15-1308, consolidated with *Walter Coke, Inc., v. EPA*, 15-1166(D.C. Cir.) *Luminant et al. v. EPA*, 15-60424 (5th Cir.) (transferred to D.C. Cir. on 8/31/15)	On 8/31/15, the State of Texas filed its petition for review in the D.C. Circuit and on 7/10/15 in the Fifth Circuit. On 8/31/15, the 5th Circuit matter was transferred and consolidated with the D.C. Circuit proceeding. Briefing is complete and oral arguments were scheduled. The DOJ requested abatement of the case, which the Court granted on 4/24/17.	Yes—granted 4/24/17.

PENDING EPA RULE CHALLENGES BY THE STATE OF TEXAS

RULE CHALLENGED	CAUSE NOS.	CURRENT STATUS	CASE ABATED?
Supplemental Finding That it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal-and Oil-Fired Utility Steam Generating Units, 81 Fed. Reg. 24,420 (Apr. 25, 2016) (4/16/12)	*Michigan et al. (Texas) v. EPA*, 16-1204 (6/24/16) (D.C. Cir.), consolidated with 16-1127 (D.C. Cir.)	On 6/24/16, Texas joined Michigan and others in filing a petition for review of the supplemental rule. Briefing is complete. The DOJ requested abatement of the case, which the Court granted on 4/27/17.	Yes—granted 4/27/17.
Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510 (Oct. 23, 2015) Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662 (Oct. 23, 2015)	*North Dakota et al. (Texas) v. EPA,* 15-1381 (D.C. Cir.) *West Virginia et al. (Texas) v. EPA*, 15-1363 (D.C. Cir.)	On 10/23/15, Texas and others filed a petition for review of each of these rules. Briefing is complete. The DOJ requested abatement of the cases, which the Court granted on 4/28/17.	Yes—granted 4/28/17.

ATTACHMENT 3A

ORIGINAL

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

STATE OF TEXAS, and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY,
Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and REGINA A. MCCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency,
Respondents.

Case No. 16-1428

PETITION FOR REVIEW

In accordance with Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), 5 U.S.C. § 702, and Federal Rule of Appellate Procedure 15(a), the State of Texas and the Texas Commission on Environmental Quality hereby petition this Court for review of the United States Environmental Protection Agency's (EPA) final rule titled "Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS," 81 Fed. Reg. 74,504. (October 26, 2016), a copy of which is enclosed with this filing (Attachment 1).

This Court has jurisdiction and is a proper venue for this action under 42 U.S.C. § 7607(b)(1). This petition for review is timely filed within sixty days of the date of publication of the final rule in the Federal Register. *Id.* The final rule is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law. Clean Air Act § 307(d)(9), 42 U.S.C. § 7607(d)(9).

Dated: December 19, 2016

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

CRAIG J. PRITZLAFF
Assistant Attorney General
Court of Appeals–D.C. Circuit - Bar No. 56496
craig.pritzlaff@oag.texas.gov

LINDA B. SECORD
Assistant Attorney General
Application to D.C. Circuit process underway
linda.secord@oag.texas.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT

STATE OF TEXAS, and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY, *Petitioners,* v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency, *Respondents*.	}	Case No. _______________

PETITION FOR REVIEW

In accordance with Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), 5 U.S.C. § 702, and Federal Rule of Appellate Procedure 15(a), petitioners the State of Texas and the Texas Commission on Environmental Quality hereby petition this Court for review of the United States Environmental Protection Agency's (EPA) final action titled "Approval and Promulgation of Air Quality Implementation Plans; Texas; Interstate Transport of Air Pollution for the 2008 Ozone National Ambient Air Quality Standards" 81 Fed. Reg. 53,284 (August 12, 2016), a copy of which is enclosed with this filing.

This Court has jurisdiction and is a proper venue for this action under 42 U.S.C. § 7607(b)(1). The final action concerns disapproval of a portion of a state implementation plan prepared by Texas pursuant to Section 110 of the Clean Air Act, 42 U.S.C. § 7410, to implement in Texas certain provisions pertaining to the 2008 National Ambient Air Quality Standards. The final action was approved by the Regional

Administrator for EPA Region 6, pursuant to his delegated authority to act for the Administrator. Therefore, the final action is a locally or regionally applicable final action and is not "nationally applicable" or of "nationwide scope or effect." 42 U.S.C. § 7607(b). This petition for review is timely filed within sixty days of the date of publication of the Final Rule in the Federal Register. *Id.*

Dated: October 10, 2016

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

/s/ Priscilla M. Hubenak
PRISCILLA M. HUBENAK
Assistant Attorney General
Chief, Environmental Protection Division
State Bar No. 10144690
priscilla.hubenak@oag.texas.gov

CRAIG J. PRITZLAFF
Assistant Attorney General
State Bar No. 24046658
craig.pritzlaff@oag.texas.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

CERTIFICATE OF SERVICE

On October 10, 2016, the foregoing Petition for Review was served by certified mail, return receipt requested, on:

Hon. Regina A. McCarthy
Office of the Administrator (1101A)
United States Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Hon. Loretta E. Lynch
Attorney General of the United States
United States Department of Justice
950 Pennsylvania Ave., NW
Washington, DC 20530-0001

Pursuant to 40 C.F.R. § 23.12:
Correspondence Control Unit
Office of General Counsel (2311A)
United States Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington DC 20460

/s/ Priscilla H. Hubenak
PRISCILLA M. HUBENAK

ORIGINAL

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

STATE OF TEXAS, and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY,
Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and REGINA A. MCCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency,
Respondents.

Case No. 17-1021

PETITION FOR REVIEW

In accordance with Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), 5 U.S.C. § 702, and Federal Rule of Appellate Procedure 15(a), the State of Texas and the Texas Commission on Environmental Quality hereby petition this Court for review of the United States Environmental Protection Agency's (EPA) final rule titled "Protection of Visibility: Amendments to Requirements for State Plans," 82 Fed. Reg. 3,078. (Jan. 10, 2017), a copy of which is enclosed with this filing (Attachment 1).

This Court has jurisdiction and is a proper venue for this action under 42 U.S.C. § 7607(b)(1). This petition for review is timely filed within sixty days of the date of publication of the final rule in the Federal Register. *Id.* The final rule is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law. Clean Air Act § 307(d)(9), 42 U.S.C. § 7607(d)(9).

Dated: January 18, 2017

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

____
CRAIG J. PRITZLAFF
Assistant Attorney General
Court of Appeals–D.C. Circuit - Bar No. 56496
craig.pritzlaff@oag.texas.gov

LINDA B. SECORD
Assistant Attorney General
Court of Appeals–D.C. Circuit - process underway
linda.secord@oag.texas.gov

MARK A. STEINBACH
Assistant Attorney General
Court of Appeals–D.C. Circuit Bar No. 59880
mark.steinbach@oag.texas.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and CATHERINE McCABE, in her official capacity as Administrator of the United States Environmental Protection Agency, Respondents.	Case No. 17-1053

PETITION FOR REVIEW

In accordance with Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), and Federal Rule of Appellate Procedure 15, the State of Texas and the Texas Commission on Environmental Quality (collectively, State of Texas) petition the Court for review of the United States Environmental Protection Agency's (EPA) final action entitled "Air Quality Designations for the 2010 Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard (NAAQS)," 81 Fed. Reg. 89,870 (Dec. 13, 2016), a copy of which is enclosed with this filing (Attachment 1).

Jurisdiction and venue for this petition is proper in the Fifth Circuit Court of Appeals because the Final Rule is a "locally or regionally applicable" final action of the EPA Administrator. *See* 42 U.S.C. § 7607(b). The State of Texas has accordingly filed a petition for review in the Fifth Circuit to challenge the rule. Because EPA has taken the position that the rule is of "nationwide scope and effect, 81 Fed. Reg. at 89875-76, and may argue that jurisdiction and venue are proper only in this Court, the State of Texas files this petition for review in this Court as a protective matter to preserve their right to judicial review.

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for
Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

Nancy Elizabeth Olinger
NANCY ELIZABETH OLINGER
Assistant Attorney General

CRAIG J. PRITZLAFF
Assistant Attorney General

OFFICE OF THE TEXAS
ATTORNEY GENERAL
Environmental Protection Division (MC066)
P.O. Box 12548
Austin, Texas 78711-2548
Tel: (512) 475-4013
Fax: (512) 320-0911
nancy.olinger@oag.texas.gov
craig.pritzlaff@oag.texas.gov
Counsel for the State of Texas and Texas
Commission on Environmental Quality

IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT

STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and CATHERINE McCABE, in her official capacity as Administrator of the United States Environmental Protection Agency, Respondents.	Case No. ____________

PETITION FOR REVIEW

In accordance with Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), and Federal Rule of Appellate Procedure 15, the State of Texas and the Texas Commission on Environmental Quality (collectively, State of Texas) petition the Court for review of the United States Environmental Protection Agency's (EPA) final action entitled "Air Quality Designations for the 2010 Sulfur Dioxide (SO_2) Primary National Ambient Air Quality Standard (NAAQS)," 81 Fed. Reg. 89,870 (Dec. 13, 2016), a copy of which is enclosed with this filing (Attachment 1).

Jurisdiction and venue for this petition is proper in this Court under 42 U.S.C. § 7607(b). The Final Rule establishes air quality designations for four areas in the State of Texas for the SO_2 NAAQS. Therefore, the Final Rule is a locally or regionally applicable final action of the EPA Administrator and is not "nationally applicable" or "of nationwide scope or effect." 42 U.S.C. § 7607(b). This petition for review is timely filed within sixty days of the date of publication of the Final Rule in the Federal Register. *Id.*

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for
Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF
Assistant Attorney General

OFFICE OF THE TEXAS
ATTORNEY GENERAL
Environmental Protection Division (MC066)

P.O. Box 12548
Austin, Texas 78711-2548
Tel: (512) 475-4138
Fax: (512) 320-0911
craig.pritzlaff@oag.texas.gov
Counsel for the State of Texas and Texas
Commission on Environmental Quality

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY Petitioner	
v.	Case No. 12-1344
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent	

PETITION FOR REVIEW

Pursuant to section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), the State of Texas and Texas Commission on Environmental Quality hereby petition the court for review of the United State Environmental Protection Agency's final rule published in the Federal Register at 77 Fed. Reg. 33642 on June 7, 2012, titled "Regional Haze: Revisions to Provisions Governing Alternatives to Source-specific Best Available Retrofit Technology (BART) Determinations, Limited SIP disapprovals, and Federal Implementation Plans."

Respectfully submitted,

GREG ABBOTT
Attorney General of Texas

DANIEL T. HODGE
First Assistant Attorney General

JOHN B. SCOTT
Deputy Attorney General for Civil Litigation

JON NIERMANN
Chief, Environmental Protection Division

MARK L. WALTERS
Assistant Attorney General

OFFICE OF THE TEXAS ATTORNEY GENERAL
ENVIRONMENTAL PROTECTION DIVISION
P. O. Box 12548, MC-066
Austin, Texas 78711-2548
(512) 463-2012 Telephone
(512) 320-0911 Facsimile
Email: Mark.Walters@texasattorneygeneral.gov

CERTIFICATE OF SERVICE

On August 3, 2012, I served a copy of the foregoing *Petition for Review* by certified mail, return receipt requested, on the following parties of interest:

The Honorable Lisa Jackson
U.S. EPA
Office of the Administrator
1200 Pennsylvania Ave N.W.
Room 3000
Washington, D.C. 20450
Via: CMRRR #7007 1490 0000 0796 0305

Correspondence Control Unit
Office of General Counsel (2311)
U.S. EPA
1200 Pennsylvania Ave N.W.
Room 4000
Washington, D.C. 20460
Via: CMRRR #7007 1490 0000 0796 0299

IN THE UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS

STATE OF TEXAS, Texas Department of Agriculture, Texas Commission on Environmental Quality, Texas Department of Transportation, Texas General Land Office, Railroad Commission of Texas, Texas Water Development Board, STATE OF LOUISIANA, and STATE OF MISSISSIPPI, *Plaintiffs,* v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, GINA McCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency, UNITED STATES ARMY CORPS OF ENGINEERS, and JO-ELLEN DARCY, in her official capacity as Assistant Secretary of the Army (Civil Works). *Defendants.*	Case No. _________

COMPLAINT AND PETITION FOR REVIEW

TO THE HONORABLE UNITED STATES DISTRICT COURT:

1. This is a challenge to the legality of the final ru le titled "Clean Water Rule: Definition of 'Waters of the United States,'" promulgated on June 29, 2015, by defendants United States Environmental Protection Agency; and the Uni ted States Army Corps of Engineers ("Federal Agencies"). Clean Water Rule: Definition of "Waters of the United States," 80 Fed. Reg.

37,054 (June 29, 2015) (to be codified at 33 C.F.R. pt. 328 and 40 C.F.R. pts. 110, 112, 116, 117, 122, 230, 232, 300, 302, and 401) ("Final Rule").

2. The Final Rule is an unconstitutional and impermissible expansion of federal power over the states and their citizens and property owners. Whereas Congress defined the limits of its commerce power through the Clean Water Act to protect the quality of American waters, the Environmental Protection Agency and Army Corps of Engineers, through the Final Rule, are attempting to expand their authority to regulate water and land use by the states and their citizens. The success of protecting and improving the quality of American waters has come through the cooperative work of the states and the federal government. That success is threatened when administrative agencies attempt to substitute their judgment for decisions by Congress, the courts, and the states. Moreover, the very structure of the Constitution, and therefore liberty itself, is threatened when administrative agencies attempt to assert independent sovereignty and lawmaking authority that is superior to the states, Congress, and the courts.

3. The challenge is brought by the State of Texas, by and through its Attorney General, Ken Paxton, along with the Texas Department of Agriculture, Texas Commission on Environmental Quality, Texas Department of Transportation, Texas General Land Office, Railroad Commission of Texas, and Texas Water Development Board. The challenge is also brought by the State of Louisiana, by and through its Attorney General, Buddy Caldwell, and the State of Mississippi, by and through its Attorney General, Jim Hood.

4. The Final Rule amends the definition of "Waters of the United States" under the Federal Water Pollution Control Act, 33 U.S.C. §§ 1251 *et seq.* ("Clean Water Act" or "CWA"). A true and correct copy of the Final Rule is attached hereto at Exhibit A.

5. The Final Rule violates the Clean Water Act, the Administrative Procedure Act, and the United States Constitution, as noted below. Plaintiffs ask this Court to vacate the Final Rule, to enjoin the Federal Agencies from enforcing the Final Rule, and for any other relief as this Court deems proper.

I. PARTIES

6. Plaintiffs are the State of Texas, along with the Texas Department of Agriculture, Texas Commission on Environmental Quality, Texas Department of Transportation, Texas General Land Office, Railroad Commission of Texas, and Texas Water Development Board; the State of Louisiana; and the State of Mississippi.

7. The State of Texas and its state agencies, by and through its Attorney General, bring this suit to assert the rights of the state and also on behalf of its citizens.[1]

8. The State of Louisiana, by and through its Attorney General, James D. "Buddy" Caldwell, brings this suit pursuant to authority vested in its Attorney General to "institute, prosecute, or intervene in any civil action or proceeding" as "necessary for the assertion or protection of any right or interest of the state." La. Const. Art. IV, Sec. 8. The State of Louisiana also brings this action as *parens patriae* for all Louisiana residents who are adversely affected by the Final Rule's violations of the Clean Water Act, the Administrative Procedure Act, and the United States Constitution.

9. The State of Mississippi, by and through its Attorney General, Jim Hood, brings this suit pursuant to authority vested in its Attoney General "to bring or defend a lawsuit on behalf of a state agency, the subject matter of which is of statewide interest" and "intervene and argue the constitutionality of any statute when notified of a challenge thereto." 7 Miss. Code § 7-5-1. The

[1] *See* Tex. Const. Art. 4, § 22; Tex. Gov't Code, Ch. 402; *see also* Tex H.B. 1, Art. IX, § 16.01, 82nd Tex. Leg., R.S. (2011).

State of Mississippi also brings this action as *parens patriae* for all Mississippi residents who are adversely affected by the Final Rule's violations of the Clean Water Act, the Administrative Procedure Act, and the United States Constitution.

10. Defendant United States Environmental Protection Agency ("EPA") is a federal agency within the meaning of the Administrative Procedure Act ("APA"). *See* 5 U.S.C. § 551(1). Pursuant to the Clean Water Act, the EPA is provided with the authority, *inter alia*, to administer pollution control programs over navigable waters.

11. Defendant the Honorable Gina McCarthy is Administrator of the EPA and a signatory of the Final Rule.

12. Defendant United States Army Corps of Engineers ("Corps") is a federal agency within the meaning of the APA. *See* 5 U.S.C. § 551(1). The Corps, *inter alia*, administers the Clean Water Act's Section 404 program, regulating the discharge of dredged or fill material in navigable waters.

13. Defendant the Honorable Jo-Ellen Darcy is Assistant Secretary of the Army (Civil Works) and a signatory of the Final Rule.

II. JURISDICTION AND VENUE

14. This Court has jurisdiction over this action by virtue of 28 U.S.C. §§ 1331 (federal question), 2202 (further necessary relief), and 5 U.S.C. §§ 701–706 (APA). There is a present and actual controversy between the parties, and Plaintiffs are challenging a final agency action pursuant to 5 U.S.C. §§ 551(13), and 704. The Court may issue further necessary relief pursuant to 28 U.S.C. § 2202, 5 U.S.C. §§ 706(1), 706(2)(A) and (C), as well as pursuant to its general equitable powers.

15. Venue is proper in this Court pursuant to 28 U.S.C. § 1391(e)(1)(C), because (1) Defendants are either (a) agencies or instrumentalities of the United States or (b) officers or employees of the United States, acting in their official capacities; (2) Plaintiff State of Texas and its agencies are residents of the Southern District of Texas;[2] and (3) no real property is involved in this action.

16. Because there may be a dispute between the parties as to whether original jurisdiction to review the Final Rule lies in this Court, pursuant to 28 U.S.C. § 1331, or in the U.S. Court of Appeals for the Fifth Circuit, pursuant to 33 U.S.C. § 1369(b)(1), and because the deadline for a circuit court petition for review of this agency action is only 120 days, *id.*, Plaintiffs have—out of an abundance of caution—filed a petition in the U.S. Court of Appeals for the Fifth Circuit, to challenge the Final Rule on similar grounds as those asserted herein. Such "dual filing" is common and prudent when jurisdiction may be disputed, and "careful lawyers must apply for judicial review [in the court of appeals] of anything even remotely resembling" an action reviewable under section 509(b)(1), *see Am. Paper Inst. v. EPA*, 882 F.2d 287, 288 (7th Cir. 1989), even when they believe that jurisdiction may lie elsewhere. *See Cent. Hudson Gas & Elec. Corp. v. EPA*, 587 F.2d 549, 554 (2nd Cir. 1978) (complaint filed in district court and petition filed in circuit court "as a precaution").

III. BACKGROUND

A. The Clean Water Act Maintains the States' Regulatory Authority Over Land and Water

17. When Congress enacted the Clean Water Act Amendments of 1972, it made abundantly clear its goal to grant primary regulatory authority over land and waters to the States:

> It is the policy of the Congress to recognize, preserve, and protect the primary responsibilities and rights of States to prevent, reduce, and eliminate pollution, to plan the development and use . . . of land and water

[2] *See Delaware v. Bender*, 370 F. Supp. 1193, 1200 (D. Del. 1974).

> resources, and to consult with the Administrator in the exercise of his authority under this chapter.

33 U.S.C. § 1251(b).

18. The Clean Water Act does, however, grant limited authority to the Federal Agencies to regulate the discharge of certain materials into "navigable waters." *See*, *e.g.*, 33 U.S.C. § 1251(a), 1342(a), 1344(a).

19. Congress defined "navigable waters" as "the waters of the United States, including the territorial seas." 33 U.S.C. § 1362(7).

20. The meaning of "the waters of the United States" is significant, because it establishes, among other things, the waters for which the Federal Agencies can require Water Quality Standards ("WQS") and Total Maximum Daily Loads ("TMDLs"); the waters for which the Federal Agencies can administer permitting programs like the National Pollutant Discharge Elimination System ("NPDES") and section 404 dredge or fill permitting programs; and the waters for which the Federal Agencies can require state certifications for any discharge activity.

21. Obtaining a discharge permit is an expensive and uncertain endeavor that can take years of processing and cost hundreds of thousands of dollars. *See* U.S.C. §§ 1342, 1344. But discharging into a "water of the United States" without a permit can subject any person to civil penalties of up to $37,500 per violation, per day, as well as criminal penalties. *See Hanousek v. United States*, 528 U.S. 1102, 1103 (2000); *see also* 33 U.S.C. §§ 1311, 1319, 1365; 74 Fed. Reg. 626, 627 (2009).

22. In general, a broader definition of "the waters of the United States" will place more waters under federal authority. On the other hand, a more limited definition of "the waters of the United States" will place more waters under state and local authority. Therefore, the meaning of "the waters of the United States" is significant because it defines the parameters of cooperative

federalism under the Clean Water Act and determines whether Congress's wish "to recognize, preserve, and protect the primary responsibilities and rights of States to prevent, reduce, and eliminate pollution, to plan the development and use . . . of land and water resources" will be honored. 33 U.S.C. § 1251(b).

B. The Meaning of "the Waters of the United States"

23. More than 100 years before the passage of the Clean Water Act Amendments of 1972, the Supreme Court defined the phrase "navigable waters of the United States" as "navigable in fact" interstate waters. *The Daniel Ball*, 10 Wall. 557, 563 (1871).

24. In 1974, the Corps issued a rule defining "navigable waters" as those waters that have been, are, or may be used for interstate or foreign commerce. 33 C.F.R. § 209.120(d)(1) (1974).

25. In 1986, the Corps issued another rulemaking, expanding its jurisdiction to include traditional navigable waters, tributaries of those waters, wetlands adjacent to those waters and tributaries, and waters used as habitat by migratory birds that either are protected by treaty or cross state lines. *See* Final Rule for Regulatory Programs of the Corps of Engineers, 51 Fed. Reg. 41,206 (Nov. 13, 1986).

26. From 1986 to 2015, the regulatory definition of "the waters of the United States" remained unchanged. *See* 33 C.F.R. 328 (1986). Markedly, during that time, the only development of the definition was in the judicial branch, where the Supreme Court took an increasingly narrow interpretation of what constitutes "the waters of the United States." *See Rapanos v. United States*, 547 U.S. 715 (2006); *Solid Waste Agency of N. Cook Cnty. v. Army Corps of Eng'rs*, 531 U.S. 159 (2001); *United States v. Riverside Bayview Homes, Inc.*, 474 U.S. 121 (1985).

i. *Riverside Bayview*

27. The Supreme Court first addressed the proper interpretation of "the waters of the United States" under the Clean Water Act in *United States v. Riverside Bayview Homes, Inc.*, 474 U.S. 121 (1985).

28. *Riverside Bayview* concerned a wetland that "was adjacent to a body of navigable water," because "the area characterized by saturated soil conditions and wetland vegetation extended beyond the boundary of respondent's property to . . . a navigable waterway." *Id.* at 131.

29. The Supreme Court upheld the Corps' interpretation of "the waters of the United States" to include wetlands that "actually abut[ted]" on traditional navigable waters, finding that "the Corps must necessarily choose some point at which water ends and land begins." *Id.* at 132.

ii. *SWANCC*

30. Fifteen years later, in *Solid Waste Agency of Northern Cook County v. Army Corps of Engineers* ("*SWANCC*"), the Supreme Court rejected the Corps' assertion of jurisdiction over any waters "[w]hich are or would be used as habitat" by migratory birds. 531 U.S. 159, 164 (2001) (quoting 51 Fed. Reg. 41,217 (1986)). The Court held that the Clean Water Act cannot be read to confer jurisdiction over physically isolated, wholly intrastate waters. *Id.* at 168. The Court found that "[i]n order to rule for respondents here, we would have to hold that the jurisdiction of the Corps extends to ponds that are *not* adjacent to open water. But we conclude that the text of the statute will not allow this." *Id.*

31. Observing that "[i]t was the *significant nexus* between the wetlands and the 'navigable waters' that informed [the Court's] reading of the CWA in *Riverside Bayview*," the Court held that *Riverside Bayview* did not establish that federal jurisdiction "extends to ponds that are not adjacent to open water." *Id.* (emphasis added).

32. In *SWANCC*, the Court reiterated its holding in *Riverside Bayview* that federal jurisdiction extends to wetlands that actually abut navigable waters, because protection of these adjacent, actually-abutting wetlands was consistent with congressional intent to regulate wetlands that are "inseparably bound up with 'waters of the United States.'" *Id.* at 172 (quoting *Riverside Bayview*, 474 U.S. at 134).

iii. *Rapanos*

33. In *Rapanos v. United States*, 547 U.S. 715 (2006), the Supreme Court again rejected the Corps' assertion of expanded authority over non-navigable, intrastate waters that are not significantly connected to navigable, interstate waters. The Court emphasized that the traditional concept of "navigable waters" must inform and limit the construction of the phrase "the waters of the United States." *Rapanos* raised the question of whether wetlands that "lie near ditches or man-made drains that eventually empty into traditional navigable waters" are "waters of the United States." *Rapanos*, 547 U.S. at 729. The court of appeals held they were, but the Supreme Court held that they were not. *Id.* at 716–17. The Court's majority consisted of two opinions, both of which rejected the Corps' assertion of jurisdiction.

34. Citing the ordinary meaning of "the waters of the United States," the four-justice plurality held that "waters of the United States" include "only relatively permanent, standing or flowing bodies of water," such as "streams, oceans, rivers, lakes, and bodies of water forming geographical features." *Id.* at 732–33 (internal quotation marks omitted). The plurality found that in going beyond this "commonsense understanding" and classifying waters like "ephemeral streams," "wet meadows," "man-made drainage ditches" and "dry arroyos in the middle of the desert" as "waters of the United States," the Corps had stretched the statutory text "beyond parody." *Id.* at 734 (internal quotation marks omitted). The plurality also rejected the view that

wetlands adjacent to ditches, when those ditches do not meet the definition of "waters of the United States," may nevertheless be subjected to federal regulation on the theory that they are "adjacent to" the remote "navigable waters" into which the ditches ultimately drain. *Id.* at 739–40.

35. Justice Kennedy concurred in the judgment, but noted that both the plurality and the dissent would expand CWA jurisdiction beyond permissible limits. He wrote that the plurality's coverage of "remote" wetlands with a surface connection to small streams would "permit application of the statute as far from traditional federal authority as are the waters it deems beyond the statute's reach" (i.e., wetlands near to, but lacking a continuous surface connection with, navigable-in-fact waters). *Id.* at 776–77 (Kennedy, J., concurring in the judgment). This, he said, was "inconsistent with the Act's text, structure, and purpose." *Id.* at 776 (Kennedy, J., concurring in the judgment). As for the dissent, Justice Kennedy said the Act "does not extend so far" as to "permit federal regulation whenever wetlands lie alongside a ditch or drain, however remote and insubstantial, that eventually may flow into traditional navigable waters." *Id.* at 778–79 (Kennedy, J., concurring in the judgment). As a result, Justice Kennedy rejected both sides' jurisdictional theories, refuting tests that rely on mere hydrologic connections to, and mere proximity to, navigable waters or features that drain into them.

36. Justice Kennedy employed a different test. In his view, the Corps may deem a water or wetland "a 'navigable water' under the Act" if it has a "significant nexus" to a traditional navigable water. *Id.* at 767 (Kennedy, J., concurring in the judgment). For "wetlands adjacent to navigable-in-fact waters," Justice Kennedy thought there is a "reasonable inference of ecologic interconnection" that is sufficient to sustain the Corps' "assertion of jurisdiction for those wetlands . . . by showing adjacency alone." *Id.* at 780 (Kennedy, J., concurring in the judgment). Justice Kennedy also said the Corps "may choose to identify categories of tributaries that, due to their

volume of flow (either annually or on average), their proximity to navigable waters, or other relevant considerations, are significant enough that wetlands adjacent to them are likely . . . to perform important functions for an aquatic system incorporating navigable waters." *Id.* at 781 (Kennedy, J., concurring in the judgment). But the Federal Agencies' regulations, which allow "regulation of drains, ditches, and streams remote from any navigable-in-fact water and carrying only minor water volumes toward it," were so broad that they could not be "the determinative measure of whether adjacent wetlands are likely to play an important role in the integrity" of traditional navigable waters. *Id.* "Indeed, in many cases wetlands adjacent to tributaries covered by this standard might appear little more related to navigable-in-fact waters than were the isolated ponds held to fall beyond the Act's scope in *SWANCC*." *Id.* at 781–82 (Kennedy, J., concurring in the judgment). Given the over-breadth of the regulations, Justice Kennedy concluded that the Corps "must establish a significant nexus on a case-by-case basis when it seeks to regulate wetlands based on adjacency to non-navigable tributaries." *Id.* at 782 (Kennedy, J., concurring in the judgment).

37. Neither the plurality opinion nor Justice Kennedy's opinion in *Rapanos* repudiated any aspect of the *SWANCC* or *Riverside Bayview* decisions.

C. Despite Contrary Precedent, the Federal Agencies Redefine "Waters of the United States" to Expand Clean Water Act Jurisdiction

38. On April 21, 2014, the Federal Agencies published for comment "Definition of 'Waters of the United States' Under the Clean Water Act." *See* 79 Fed. Reg. 22,188 (proposed April 21, 2014) (to be codified at 33 C.F.R. pt. 328 and 40 C.F.R. pts. 110, 112, 116, 117, 122, 230, 232, 300, 302, and 401) ("Proposed Rule").

39. The stated purpose for the rulemaking is to "defin[e] the scope of waters protected under the [CWA], in light of the statute, science, Supreme Court decisions . . . and the agencies'

technical expertise." Final Rule at 37,054. The Federal Agencies assert that the rule will "increase CWA program predictability and consistency by clarifying the scope of "waters of the United States" protected under the Act." *Id.*

40. On May 27, 2015, Administrator McCarthy and Assistant Secretary Darcy took final agency action when they signed the Final Rule.

41. On June 29, 2015, the Final Rule was published in the Federal Register. This Rule amends 33 C.F.R. § 328 as well as 40 C.F.R. §§ 110, 112 116, 117, 122, 230, 232, 300, 302, and 401, to be effective as of August 28, 2015. Accordingly, the Federal Agencies' promulgation of the Final Rule is now ripe for judicial review.

i. The Final Rule Maintains *Per se* Federal Jurisdiction Over Certain Waters

42. The Final Rule reasserts that traditional navigable waters, interstate waters, territorial seas, and impoundments of jurisdictional waters are jurisdictional by rule. 33 C.F.R. § 328.3(a)(1)-(4) (2015).[3]

43. Plaintiffs do not dispute that these waters have traditionally been jurisdictional. For purposes of clarity, these waters will be referred to as "traditional waters".

ii. The Federal Agencies Broadly Define "Tributaries" and Claim *Per se* Jurisdiction over All "Tributaries" of Traditional Waters

44. The Final Rule asserts that all "tributaries" of al traditional waters are jurisdictional by rule. *See id.* § 328.3(a)(5).

45. Furthermore, the Final Rule defines "tributary" for the first time as "a water that contributes flow, either directly or through another water" to a traditional water and "is

[3] The Final Rule amends the definition of "the waters of the United States" under 33 C.F.R. § 328, as well as 40 C.F.R. §§ 110, 112, 116, 117, 122, 230, 232, 300, 302, and 401. For simplicity, Plaintiffs will only cite to 33 C.F.R. § 328, but Plaintiffs' arguments apply to all C.F.R. sections amended under the Final Rule.

characterized by the presence of the physical indicators of a bed and bank and an ordinary high water mark." *Id.* § 328.3(c)(3).

46. Under the Final Rule, a tributary can be "natural, man-altered, or man-made water and includes waters such as rivers, streams, canals, and ditches . . . ." *Id.* A water does not lose its classification as a tributary—even when it has man-made or natural breaks, no matter the length—"so long as a bed and banks and ordinary high water mark can be identified upstream of the break." *Id.*

47. "Ordinary high water mark" is defined as "that line on the shore established by the fluctuations of water and indicated by physical characteristics such as a clear, natural line impressed on the bank, shelving, changes in the character of soil, destruction of terrestrial vegetation, the presence of litter and debris, or other appropriate means." *Id.* § 328.3(c)(6).

48. The Final Rule fails to account for frequency and duration of flow, meaning the Federal Agencies can assert jurisdiction over "tributaries" in the forms of dry ponds, ephemeral streams, intermittent channels, and even ditches—as long as the Federal Agencies can find a bed and banks and the existence, at some point in history, of an ordinary high water mark.

49. Despite championing Justice Kennedy's concurrence in *Rapanos* throughout the Final Rule, the Federal Agencies ignore Justice Kennedy's admonishment concerning the use of the "ordinary high water mark" as a determinative measure for tributaries. Justice Kennedy stated that "the breadth of the standard—which seems to leave wide room for regulation of drains, ditches, and streams remote from any navigable-in-fact water and carrying only minor water volumes toward it—precludes its adoption as the determinative measure . . . ." *Rapanos*, 547 U.S.

at 782 (Kennedy, J., concurring in the judgment).[4] Not only do the Federal Agencies adopt the "ordinary high water mark" as a determinative measure for tributaries in the Final Rule—they greatly expand it from the Proposed Rule. The Proposed Rule required "the *presence* of a bed and banks and ordinary high water mark," *see* Proposed Rule at 22,199, while the Final Rule requires the "presence of *physical indicators* of a bed and banks and ordinary high water mark." 33 C.F.R. § 328.3(c)(3) (2015) (emphasis added).

50. Assuming, *arguendo*, that Justice Kennedy intended the "significant nexus" test in *Rapanos* to be stretched to tributaries, the Final Rule would fail that test, because it places all tributaries of traditional waters under the Federal Agencies' authority without regard to the tributaries' actual impact on the "chemical, physical, and biological integrity of" any traditional waters. *See Rapanos*, 547 U.S. at 717. Under the Final Rule, a tributary that only has a small, infrequent, and historically-traceable flow into a traditional water, is nevertheless within the Federal Agencies' jurisdiction. 33 C.F.R. § 328.3(c)(3) (2015).

51. The Final Rule's inclusion of tributaries also violates the plurality's opinion in *Rapanos* because the definition includes a feature with any flow into a traditional water, even if that flow does not constitute a "continuous surface connection." *Rapanos*, 547 U.S. at 742.

iii. The Federal Agencies Broadly Define "Significant Nexus" and Claim *Per se* Federal Jurisdiction Over Certain Waters They Deem to Have a "Significant Nexus" to Traditional Waters

52. For the purpose of determining whether or not a water has a "significant nexus," the Final Rule requires that the water's effect on a downstream traditional water be assessed by evaluating the following functions: (i) sediment trapping; (ii) nutrient recycling; (iii) pollutant

[4] The Federal Agencies contradict Justice Kennedy even further by explicitly including "ditches" in the regulatory definition of "tributary." *Compare* 33 C.F.R. § 328.3(a)(5), *with Rapanos*, 547 U.S. at 782 (Kennedy, J., concurring in the judgment).

trapping, transformation, filtering, and transport; (iv) retention and attenuation of flood waters; (v) runoff storage; (vi) contribution of flow; (vii) export of organic matter; (viii) export of food resources; and (ix) provision of life-cycle-dependent aquatic habitat (such as foraging, feeding, nesting, breeding, spawning, or use as a nursery area) for species located in a traditional navigable water, interstate water, and/or territorial sea. 33 C.F.R. § 328.3(c)(5) (2015).

53. Under the Final Rule, a water has a "significant nexus" "when any single function or combination of functions performed by the water, alone or together with similarly situated waters in the region, contributes significantly to the chemical, physical, and biological integrity" of the downstream traditional navigable water, interstate water, and/or territorial sea. *Id.* This definition exceeds Clean Water Act authority under *SWANCC* and *Rapanos*. In *SWANCC*, the Court refused the federal government's assertion of jurisdictional authority over an isolated, intrastate water because of the Migratory Bird Rule. *See SWANCC*, 531 U.S. at 168. Under the Final Rule's framework, the Federal Agencies have effectively reasserted the theory previously rejected in *SWANCC*—that the federal government can assert jurisdiction when, for example, the nesting of migratory birds, "alone or together with similarly situated waters in the region, contributes significantly to the chemical, physical, and biological integrity" of the downstream traditional navigable water, interstate water, and/or territorial sea. *See* 33 C.F.R. § 328.3(c)(5)(ix) (2015).

iv. The Federal Agencies Broadly Define "Adjacent Waters" and Claim *Per se* Jurisdiction Over All Adjacent Waters

54. The next category of waters deemed automatically jurisdictional by the Final Rule are all waters that are "adjacent" to traditional waters, impoundments, or tributaries. *See id.* § 328.3(a)(5). But in claiming *per se* jurisdiction over all "neighboring" waters—whether or not

there is a significant nexus and whether or not there is a continuous surface connection—the Final Rule goes beyond the authority of the Clean Water Act and the opinions in *Rapanos*.

55. "Adjacent waters" are waters "bordering, contiguous or neighboring" traditional waters, impoundments, or tributaries. *Id.* at § 328.3(c)(1). The category includes "wetlands, ponds, lakes, oxbows, impoundments, and similar water features," as well as "waters separated by constructed dikes or barriers, natural river berms, beach dunes." *Id.* at § 328.3(a)(5).

56. "Neighboring" is defined as "(1) [w]aters located in whole or part within 100 feet of the ordinary high water mark of a traditional navigable water, interstate water, the territorial seas, an impoundment of a jurisdictional water, or a tributary; . . .(2) [w]aters located in whole or part in the 100-year floodplain and that are within 1,500 feet of the ordinary high water mark of a traditional navigable water, interstate water, the territorial seas, an impoundment of a jurisdictional water, or a tributary; . . . or (3) [w]aters located in whole or in part within 1,500 feet of the high tide line of a traditional navigable water or the territorial seas." *Id.* at § 328.3(c)(2).

57. Even when a water does not meet the criteria of "neighboring," it can still be jurisdictional as an "adjacent water" through a case-by-case significant-nexus analysis as proposed under the Final Rule. *See id.* at § 328.3(a)(7)–(8).

58. From a legal standpoint, the Final Rule's coverage of all "adjacent waters" fails both Justice Kennedy's and the plurality's tests under *Rapanos*.

59. The Final Rule's coverage of all "adjacent waters" is inconsistent with Justice Kennedy's approach because, among other things, it grants *per se* jurisdiction to waters that have no "significant nexus" to traditional waters of the United States. Instead, the Final Rule will establish federal jurisdiction over water features never contemplated under *SWANCC* or *Rapanos* by virtue of simply being near—not connected to—traditional waters of the United States. *See*

Rapanos, 547 U.S. at 779 (Kennedy, J., concurring in the judgment). The Final Rule's coverage of all "adjacent waters" is inconsistent with the plurality's test because, among other things, it grants *per se* jurisdiction to waters that have no "continuous surface connection" to traditional waters of the United States. *Id.* at 772 (Kennedy, J., concurring in the judgment).

60. From a practical standpoint, the Final Rule's definition of "adjacent waters" does nothing to further the Federal Agencies' express goal to "clarify the scope of waters protected under the CWA." For a landowner, including a state, to determine whether a particular water feature is subject to the Federal Agencies' jurisdiction (and, therefore, subject to permitting requirements under the CWA), the landowner would be forced to perform—or, more likely, pay an expert to perform—the following analysis:

<u>Step 1</u>

Landowner must determine the location of the ordinary high water mark of the nearest traditional navigable water, interstate water, territorial sea, impoundment of a jurisdictional water, or tributary, as defined by the Final Rule;

<u>Step 2</u>

Landowner must determine whether <u>any part</u> of the feature at issue is within 100 feet of the ordinary high water mark *or* within 1,500 feet of the high tide line. If so, then the *entire water feature* is subject to federal jurisdiction. If not, the landowner can proceed to step 3;

<u>Step 3</u>

Landowner must determine where the 100-year floodplain is located[5] and whether <u>any part</u> of the feature at issue is within the 100-year floodplain of a traditional navigable water, interstate water, territorial sea, impoundment of a

[5] This may be a difficult task. When discussing their reliance on the 100-year floodplain in the preamble to the Final Rule, the Federal Agencies acknowledge that "much of the United States has not been mapped by FEMA and, in some cases, a particular map may be out of date and may not accurately represent existing circumstances on the ground. The agencies will determine if a particular map is no longer accurate based on factors, such as streams or rivers moving out of their channels with associated changes in the location of the floodplain. In the absence of applicable FEMA maps, or in circumstances where an existing FEMA map is deemed by the agencies to be out of date, the agencies will rely on other available tools to identify the 100-year floodplain . . . ." Final Rule at 37,081.

jurisdictional water, or tributary, as defined by the Final Rule. If so, proceed to Step 4. If not, proceed to Step 5.

⇩

Step 4

Landowner must determine whether any part of the feature at issue is within 1,500 feet of the ordinary high water mark of the water found in Step 3. If so, then the entire feature at issue is subject to federal jurisdiction. If not, Landowner must proceed to Step 5.

⇩

Step 5

Landowner must determine whether any part of the feature at issue is within 4,000 feet from the ordinary high water mark of a traditional navigable water, interstate water, territorial sea, impoundment of a jurisdictional water, or tributary, as defined by the Final Rule. If so, proceed to Step 6. If not, still proceed to Step 6.

⇩

Step 6

If any part of the feature at issue is within the 100-year floodplain of a traditional navigable water, interstate water, or territorial sea *or* within 4,000 feet from the ordinary high water mark of a traditional navigable water, interstate water, territorial sea, impoundment of a jurisdictional water, or tributary, as defined by the Final Rule, Landowner must then have a case-by-case significant nexus analysis performed on the feature at issue and the relevant water.

⇩

Step 7

If the Federal Agencies determine that the feature at issue has a significant nexus to the relevant traditional navigable water,interstate water, territorial sea, impoundment, or tributary, the feature is subject to federal jurisdiction. If the Federal Agencies determine that the feature does not have a significant nexus to the relevant traditional navigable water, interstate water, territorial sea, impoundment, or tributary, the feature at issue is not subject to federal jurisdiction.

61. It is unrealistic for the Federal Agencies to expect that landowners will possess the expertise, patience, and resources to employ this onerous test to determine whether their land can fall under the Final Rule's definition of "adjacent waters." Nor should states and their taxpayers

be forced to spend funds for such onerous jurisdictional determinations. Moreover, it is unrealistic for the Federal Agencies to expect that such a complicated standard can be applied predictably and consistently across the nation.

62. In addition to exceeding practicality and Supreme Court precedent, the Federal Agencies' promulgation of the broad definition of "adjacent waters" violates notice requirements under the APA.

63. The APA requires agencies to provide a "[g]eneral notice of proposed rulemaking" and provide "interested persons an opportunity to participate in the rulemaking through submission of written data, views, or arguments . . . ." 5 U.S.C. §§ 553(b)–(c). This includes the requirement that an agency's final rule may differ from its proposed rule only to the extent that the final rule is a "logical outgrowth" of the rule as originally proposed. *See Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). And a final rule is a logical outgrowth of a proposed rule only to the extent that interested parties "'should have anticipated' that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Ne. Md. Waste Disposal Auth. v. EPA*, 358 F.3d 936, 952 (D.C. Cir. 2004) (quoting *Waukesha v. EPA*, 320 F.3d 228, 245 (D.C. Cir. 2003)).

64. In both the Proposed Rule and the Final Rule, waters that are "adjacent" to traditional waters, and tributaries and impoundments of traditional waters, are themselves "waters of the United States." And, in both the proposed and final rules, "adjacent waters" include "neighboring waters." *See* Proposed Rule at 22,260; *see also* 33 C.F.R. § 328.3(a)(5) (2015).

65. In the Proposed Rule, however, neighboring waters were defined in terms of a hydrological connection. Specifically, "neighboring waters" were "waters with a shallow subsurface hydrologic connection or confined surface hydrologic connection to such a

jurisdictional water." *See* Proposed Rule at 22,261, 22,271. Further, a "riparian area" was defined as "an area bordering a water where surface or subsurface hydrology directly influence the ecological processes and plant and animal community structure in that area." *Id.* In the Proposed Rule, the Federal Agencies' justification for regulating "adjacent waters" was based on what it deemed to be their "significant nexus"—as that term was used by Justice Kennedy—to traditional waters in that such adjacent waters "significantly affect the chemical, physical, and biological integrity of those waters." *Id.* at 22,260.

66. In the Final Rule, "riparian" is nowhere to be found, and the only reference to subsurface hydrology is in the exceptions to federal jurisdiction. 33 C.F.R. § 328.3(b)(5) (2015). Instead, the Final Rule defines "neighboring waters" exclusively in terms of distance—not hydrological connection—to traditional waters, impoundments, and tributaries. *See id.* § 328.3(c)(2).

67. There was no reason for Plaintiffs to anticipate a change in the definition of "adjacent" waters from hydrological connection to distance alone, especially because the latter is wholly without support in either the plurality opinion or Justice Kennedy's concurrence in *Rapanos*. Accordingly, the Final Rule's definition of "adjacent" waters is not a logical outgrowth of the Proposed Rule.

68. This sweeping inclusion of "adjacent" waters exceeds the Federal Agencies' authority under the Clean Water Act, violates the APA, and goes beyond the precedent established in *Riverside Bayview*, *SWANCC*, and *Rapanos*.

v. The Final Rule Establishes Two Categories of "Waters" that Will Be Evaluated on a Broad Case-by-Case Basis

69. Under the Final Rule, two categories of waters will be subjected to a case-by-case "significant nexus" analysis. The first category, referred to as "a(7) waters," identifies five specific

subcategories of "waters" that will be subject to case-by-case determinations. 33 C.F.R. § 328.3(a)(7) (2015). These include prairie potholes, Carolina bays and Delmarva bays, pocosins, Western vernal pools, and Texas coastal prairie wetlands. *Id.* These "a(7) waters" are deemed jurisdictional when they are determined on a case-specific basis to have a "significant nexus" to a traditional navigable water, interstate water, or territorial sea. *Id.* The Final Rule further states that "a(7) waters" that lie within the same watershed are "similarly situated" by rule and, therefore, will be aggregated for purposes of the Federal Agencies' significant nexus analysis. *Id.* § 328.3(c)(5).

70. The second category, referred to as "a(8) waters" are "[a]ll waters located within the 100-year floodplain of a [traditional water] and all waters located within 4,000 feet of the high tide line or ordinary high water mark of a [traditional water, tributary, or adjacent water]." *Id.* § 328.3(a)(8). These "a(8) waters" are deemed jurisdictional when they are determined on a case-specific basis to have a "significant nexus" to a traditional water. *Id.* Moreover, if only a "portion" of an "a(8) water" is determined to have a "significant nexus" to a traditional water, the entire "a(8) water" is subject to CWA jurisdiction. *Id.*

71. Significantly, the Federal Agencies acknowledge in their own economic analysis of the Final Rule that "the vast majority of the nation's water features are located within 4,000 feet of a covered tributary, traditional navigable water, interstate water, or territorial sea" and that the 100-year floodplain encompasses an even larger area.[6] Therefore, the Federal Agencies admit that the Final Rule will expose more than "the vast majority of the nation's water features" to the possibility of CWA jurisdiction.

[6] U.S. Envtl. Prot. Agency & U.S. Dep't of the Army, Economic Analysis of the EPA-Army Clean Water Rule (2015) at 11, http://www2.epa.gov/sites/production/files/2015-05/documents/final_clean_water_rule_economic_analysis_5-15_2.pdf.

72. This case-by-case, aggregating approach exceeds the Federal Agencies' authority under the Clean Water Act and goes beyond the precedent established in *SWANCC* and *Rapanos*.

vi. The Federal Agencies' Reliance on the "Significant Nexus" Standard Is Flawed, As Is Their Application of the Standard

73. In the preamble to the Final Rule, the Federal Agencies make clear that "[a]n important element of the agencies' interpretation of the CWA is the significant nexus standard . . . first informed by the ecological and hydrological connections the Supreme Court noted in *Riverside Bayview*, developed and established by the Supreme Court in *SWANCC*, and further refined in Justice Kennedy's opinion in *Rapanos*." Final Rule at 37,056.

74. In developing its "significant nexus" standard, however, the Final Rule relies almost exclusively on Justice Kennedy's concurrence in *Rapanos*. This reliance is misplaced. While the Federal Agencies will undoubtedly argue that relying on Justice Kennedy's concurrence is proper in a fractured opinion such as this, that opinion does not grant the Federal Agencies permission to exceed their authority under the Clean Water Act and the Constitution. Even Justice Kennedy acknowledged in *Rapanos* that "[t]o be sure, the significant-nexus requirement may not align perfectly with the traditional extent of federal authority." *Rapanos*, 547 U.S. at 782 (Kennedy, J., concurring in the judgment).

75. The Federal Agencies would have been more prudent to rely on the *Rapanos* plurality's holding that "the phrase 'the waters of the United States' includes only those relatively permanent, standing or continuously flowing bodies of water 'forming geographic features' that are described in ordinary parlance as 'streams[,] . . . oceans, rivers, [and] lakes. *Rapanos*, 547 U.S. at 739 (quoting Webster's New Int'l Dictionary 2882 (2d ed. 1954)). That standard is more expressly consistent with the goals of the Clean Water Act, *see* 33 U.S.C. §§ 1251(a)–(b), Congress's commerce power, and the underlying precedent in *Riverside Bayview* and *SWANCC*.

76. Instead, the Final Rule relies almost exclusively on a "significant nexus" standard that goes far beyond what was contemplated by Justice Kennedy in *Rapanos* and eclipses any authority under *Riverside Bayview* and *SWANCC*.

77. In *Riverside Bayview*, the Supreme Court stated that "the waters of the United States" under the Clean Water Act referred primarily to "rivers, streams, and other hydrographic features more conveniently identifiable as 'waters.'" 474 U.S. at 131. Nowhere did *Riverside Bayview* suggest that "the waters of the United States" should include anything beyond that.

78. In *SWANCC*, the Supreme Court reiterated its holding in *Riverside Bayview* that wetlands that were "inseparably bound" up with traditional navigable waters constituted waters of the United States. *SWANCC*, 531 U.S. at 172. In clarifying its holding in *Riverside Bayview*, the *SWANCC* Court stated the "inseparability" between a wetland that *actually abutted* a traditional navigable water produced a "significant nexus" that guided the court's previous decision. *Id.* at 168 (emphasis added). *SWANCC* stated that under the Federal Agencies' concept of jurisdiction, the court would have to hold that the Clean Water Act extends to waters that are not adjacent to open water, and "that the text of the statute will not allow this." *Id.* Therefore, nothing in either *Riverside Bayview* or *SWANCC* suggests that the concept of a "significant nexus" justifies CWA jurisdiction over anything beyond wetlands that *actually abut* traditional navigable waters.

79. Finally, in *Rapanos*, while Justice Kennedy further developed the "significant nexus" concept, he maintained that the standard remained rooted in *Riverside Bayview*, where the court held that wetlands actually abutting navigable waters were jurisdictional because they are "integral parts of the aquatic environment" that Congress expressly chose to regulate. *Rapanos*, 547 U.S. at 779 (Kennedy, J., concurring in the judgment) (quoting *Riverside Bayview*, 474 U.S. at 135).

80. The Federal Agencies' almost exclusive reliance on a "significant nexus" standard does not provide a valid legal justification for the overly expansive definition of "the waters of the United States" in the Final Rule. The Final Rule still must comply with the Clean Water Act, the Constitution, and guiding precedent. It does not. On the contrary, the Final Rule attempts to confer federal jurisdiction to waters that were not contemplated as jurisdictional under any reasonable reading of *Rapanos*, *SWANCC*, and *Riverside Bayview*. Moreover, it is noteworthy that Justice Kennedy's concern was that both the majority- and minority-plurality opinions would expand CWA jurisdiction beyond permissible limits, *see Rapanos*, 547 U.S. at 776–77 (Kennedy, J., concurring in the judgment), thereby reinforcing Plaintiffs' position that the Federal Agencies are not properly relying on Justice Kennedy's "significant nexus" standard.

vii. The Final Rule Establishes Exclusions that Lack Certainty and Will Require Case-Specific Determinations

81. In broadly defining a number of new terms, the Federal Agencies have not only riddled the CWA with uncertain and unpredictable standards, but they have also made unclear which waters they explicitly intend to exclude from CWA jurisdiction.

82. The Final Rule excludes a list of seven types of water features, each of which contains limiting qualifications. Specifically, many of the exclusions only qualify if they "do not meet the definition of tributary," *see* 33 C.F.R. § 328.3(b)(4)(vi); "are not a relocated tributary or excavated in a tributary," *see id.* at § 328.3(b)(3)(i)–(ii); and are water features that were "created in dry land," *see id.* at §§ 328.3(b)(4)(i)–(v) and 328.3(b)(4)(vii).

83. As shown above, the Final Rule's definition of "tributary" is overbroad and in conflict with Justice Kennedy's concurrence in *Rapanos*. This will establish federal jurisdiction over waters—and lands—whose only defining characteristics are that they possess an historic "ordinary high water mark" and in some way "contribute flow."

84. Furthermore, the Federal Agencies do not define "dry land," nor do they state what "created in dry land" means. As a result, prudent property owners, including the states, will not know whether certain water features meet these exclusions unless they expend significant resources to have the proper analyses performed—all in an effort to prove to the Federal Agencies that their land should be excluded from CWA jurisdiction, and with no guarantee that they will succeed in that effort.

D. The Final Rule Harms Plaintiffs

85. The Final Rule harms Plaintiffs by (1) expanding the number of waters subject to federal regulation; (2) eroding the states' authorities over their own waters; (3) increasing the states' burdens and diminishing the states' abilities to administer their own programs; and (4) undermining the states' sovereignty to regulate their internal affairs as guaranteed by the Constitution.

86. In their own economic analysis of the Final Rule, the Federal Agencies estimate that—had the Final Rule been in place during fiscal years 2013 and 2014—the agencies would have found that an additional 2.84 to 4.65 percent of "waters" were subject to CWA jurisdiction.[7] This contradicts the Federal Agencies' statement in the preamble to the Final Rule: "The scope of jurisdiction in this rule is narrower than that under the existing regulation. Fewer waters will be defined as 'waters of the United States' under the rule than under the existing regulations." Final Rule at 37,054.

87. As a result, Plaintiffs will be required to establish water quality standards under CWA Section 303, 33 U.S.C. § 1313, for miles of newly regulated waters that will likely include

[7] U.S. Envtl. Prot. Agency & U.S. Dep't of the Army, Economic Analysis of the EPA-Army Clean Water Rule (2015) at 12–13, http://www2.epa.gov/sites/production/files/2015-05/documents/final_clean_water_rule_economic_analysis_5-15_2.pdf.

ephemeral tributaries, innumerable ponds, prairie potholes, Texas coastal prairie wetlands, and ditches. The states will be required to certify that federal actions meet those standards under CWA Section 401, 33 U.S.C. § 1341. This will impose significant, immediate harms to the states and state agencies involved in this action.

88. The Final Rule erodes Plaintiffs' authorities over their waters. The CWA clearly states that "[i]t is the policy of the Congress to recognize, preserve, and protect the primary responsibilities and rights of States to prevent, reduce, and eliminate pollution, to plan the development and use . . . of land and water resources . . . ." 33 U.S.C. § 1251(b). Moreover, the Tenth Amendment provides States with traditional authority over their own lands and waters. *See, e.g.*, *Hess v. Port Auth. Trans-Hudson Corp.*, 513 U.S. 30, 44 (1994) (holding that "regulation of land use [is] a function traditionally performed by local governments"). The Federal Rule would shift primary responsibility over traditional state lands and waters from the States to the federal government. This will impose significant, immediate harms to the States and state agencies involved in this action.

89. The Final Rule drastically increases Plaintiffs' burdens and harms Plaintiffs' abilities to administer their state programs. Because the Final Rule expands federal jurisdiction, state agencies will be forced to devote more resources to procuring CWA section 402 and 404 permits. For example, because the Final Rule defines "tributaries" to include ditches and flood channels, as well as features like prairie potholes and Texas coastal prairie wetlands, agencies will be forced to obtain CWA section 402 and/or 404 permits for work in those areas that may disturb

soil or otherwise add any pollutant that could affect those features. Individual CWA section 404 permits have a median cost of $155,000 and can take more than a year to obtain.[8]

90. Given the jurisdictional uncertainty that will be caused by the Federal Agencies' definition of "adjacent waters" and the unpredictability of the Federal Agencies' significant nexus analysis, cautious, law-abiding landowners—including governmental entities—will be forced to expend resources if there is even a remote possibility that a project may affect a water of the United States. Moreover, the vagueness of the Final Rule and the requirement of states to inquire whether waters, on a case-by-case basis, are subject to CWA jurisdiction, tortures any notion that land- and water-use are traditional rights and responsibilities of the states.

91. These factors will impose significant, immediate harms to the States and state agencies involved in this action.

IV. CLAIMS FOR RELIEF

Claim One: The Final Rule Violates the Administrative Procedure Act

92. Plaintiffs hereby re-allege and incorporate by reference the facts and allegations set forth in all preceding paragraphs as if set forth in full herein.

93. Under the APA, a final agency action may be held unlawful and set aside if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law . . .; in excess of statutory jurisdiction, authority or limitations . . .; or without observance of procedure required by law." 5 U.S.C. § 706(2).

94. The Clean Water Act only authorizes the Federal Agencies to assert jurisdiction over "navigable waters," defined as "waters of the United States." 33 U.S.C. §§ 1344, 1362(7).

[8] U.S. Envtl. Prot. Agency & U.S. Dep't of the Army, Economic Analysis of the EPA-Army Clean Water Rule (2015) at 35–39, http://www2.epa.gov/sites/production/files/2015-05/documents/final_clean_water_rule_economic_analysis_5-15_2.pdf.

95. The Final Rule exceeds the Federal Agencies' statutory authority and is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law" because it confers jurisdiction to the Federal Agencies over lands and waters that fall outside of the law established by the Clean Water Act, as interpreted by *Riverside Bayview*, *SWANCC*, and *Rapanos*. *See* 5 U.S.C. § 706(2).

96. Secondly, under the APA, an agency must provide a "[g]eneral notice of proposed rulemaking" and provide "interested persons an opportunity to participate in the rulemaking through submission of written data, views, or arguments . . . ." 5 U.S.C. §§ 553(b)–(c). This requirement includes the requirement that an administrative agency's final rule may differ from its proposed rule only to the extent that the final rule is a "logical outgrowth" of the rule as originally proposed. *See Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). And a final rule is a logical outgrowth of a proposed rule only to the extent that interested parties "'should have anticipated' that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *Ne. Md. Waste Disposal Auth. v. EPA*, 358 F.3d 936, 952 (D.C. Cir. 2004) (quoting *Waukesha v. EPA*, 320 F.3d 228, 245 (D.C. Cir. 2003)).

97. For the reasons above, the Final Rule is not a "logical outgrowth" of the proposed rule. Therefore, the Final Rule violates the APA, 5 U.S.C. §§ 553(b)–(c).

Claim Two: The Final Rule Violates the Commerce Clause

98. Plaintiffs hereby re-allege and incorporate by reference the facts and allegations set forth in all preceding paragraphs as if set forth in full herein.

99. The federal government lacks a general police power and may only exercise powers expressly granted to it by the Constitution. *See* U.S. CONST., amend. X.; *United States v. Lopez*, 514 U.S. 549, 566 (1995).

100. The Clean Water Act was enacted pursuant to Congress's authority to regulate interstate commerce under Article I, Section 8 of the Constitution. As a result, the Federal Agencies violate the Constitution when their enforcement of the Clean Water Act extends beyond the regulation of interstate commerce. *See SWANCC*, 531 U.S. at 173; *see also United States v. Darby*, 312 U.S. 100, 119–20 (1941) (holding Congress may regulate intrastate activity only where the activity has a "substantial effect" on interstate commerce).

101. The Final Rule violates the Constitution because it will subject to Clean Water Act jurisdiction thousands of miles of intrastate waters that have no substantial effect on interstate commerce. Regulating these waters falls outside the scope of Congress's—and, therefore, the Federal Agencies'—constitutional authority.

102. Therefore, the rule is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with the law . . .; in excess of statutory jurisdiction, authority or limitations . . . ; or without observance of procedure required by law." 5 U.S.C. § 706(2).

C. <u>Claim Three</u>: The Final Rule Violates State Sovereignty and the Clear Statement Canon

103. Plaintiffs hereby re-allege and incorporate by reference the facts and allegations set forth in all preceding paragraphs as set forth in full herein.

104. Under the Tenth Amendment, "[t]he powers not delegated to the United States by the Constitution . . . are reserved to the States respectively, or the people." U.S. CONST., amend. X.

105. The Final Rule encroaches upon the rights of the states to regulate lands within their borders. Land-use planning, regulation, and zoning are not enumerated powers granted to the federal government. They are the basic, fundamental functions of local governmental entities. Authority over these functions is reserved, traditionally, to the states under the Tenth

Amendment. *See SWANCC*, 531 U.S. at 174 (recognizing the "States' traditional and primary power over land and water use"); *Hess v. Port Auth. Trans-Hudson Corp.*, 513 U.S. 30, 44 (1994) ("Among the rights and powers reserved to the States under the Tenth Amendment is the authority to its land and water resources."); *FERC v. Mississippi*, 456 U.S. 742, 768, n.30 (1982) ("regulation of land use is perhaps the quintessential state activity"); *see also* 33 U.S.C. § 1251(b).

106. The courts traditionally expect "a 'clear and manifest' statement from Congress to authorize an unprecedented intrusion into traditional state authority." *Rapanos*, 547 U.S. at 738 (citing *BFP v. Resolution Trust Corp.*, 511 U.S. 531, 544 (1994)). The phrase "the waters of the United States" does not constitute such a clear and manifest statement. *Id.* On the contrary, the Clean Water Act instructs the Federal Agencies to "recognize, preserve, and protect the primary responsibilities and rights of States . . . to plan the development and use . . . of land and water resources . . . ." 33 U.S.C. § 1251(b). Thus, "where an otherwise acceptable construction of a statute would raise serious constitutional problems, the Court will construe the statute to avoid such problems unless such construction is plainly contrary to the intent of Congress." *Edward J. DeBartolo Corp. v. Fla. Gulf Coast Bldg. & Constr. Trades Council*, 485 U.S. 568, 575 (1988).

107. Therefore, the Final Rule violates the Tenth Amendment, the clear statement canon, and 33 U.S.C. § 1251(b).

PRAYER FOR RELIEF

WHEREFORE, Plaintiffs respectfully request that the Court:

(1) Adjudge and declare that the rulemaking titled "Clean Water Rule: Definition of 'Waters of the United States,'" promulgated in 33 CFR Part 328 and 40 CFR Parts 110, 112, 116, 117, 122, 230, 232, 300, 302, and 401 is unlawful because it is inconsistent

with, and in excess of, the EPA's and U.S. Army Corps of Engineers' statutory authority under the CWA;

(2) Adjudge and declare that the Final Rule is arbitrary, capricious, an abuse of discretion, and not in accordance with law;

(3) Adjudge and declare that the Final Rule violates the Constitution of the United States.

(4) Vacate the Final Rule;

(5) Award Plaintiffs their reasonable fees, costs, expenses, and disbursements, including attorney's fees, associated with this litigation; and grant Plaintiffs such additional and further relief as the Court may deem just, proper, and necessary.

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

BERNARD L. McNAMEE
Chief of Staff

SCOTT A. KELLER
Solicitor General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

JON NIERMANN
Chief, Environmental Protection Division

/s/ *Matthew B. Miller*
MATTHEW B. MILLER*
Assistant Attorney General
Texas Bar No. 24074722
matt.miller@texasattorneygeneral.gov
Southern District Admission Pending

LINDA B. SECORD
Assistant Attorney General
Texas Bar No. 17973400
linda.secord@texasattorneygeneral.gov
Southern District Bar No. 1850549

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax. (512) 320-0911

Attorneys for the State of Texas

JAMES D. "BUDDY" CALDWELL
Attorney General of Louisiana

TREY PHILIPS
First Assistant Attorney General

/s/ Megan K. Terrell
MEGAN K. TERRELL
Deputy Director – Civil Division
Chief – Environmental Section
Assistant Attorney General
La. Bar Roll No. 29443
Southern District ID No. 1850544
Office of the Louisiana Attorney General
1885 N. Third Street
Baton Rouge, Louisiana 70802
Phone: (225) 326-6020
Fax: (225) 326-6099

Attorneys for the State of Louisiana

JIM HOOD
Attorney General of the State of Mississippi

/s/ *Mary Jo Woods*
MARY JO WOODS*
Special Assistant Attorney General
Miss. Bar No. 10468
Mississippi Attorney General's Office
Post Office Box 220
Jackson, Mississippi 39205
Phone: (601) 359-3020
Facsimile: (601) 359-2003
Email: mwood@ago.state.ms.us

Attorneys for the State of Mississippi

* Motion and Order for Admission *Pro Hac Vice* filed with the Court

IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT

STATE OF TEXAS, Texas Department of Agriculture, Texas Commission on Environmental Quality, Texas Department of Transportation, Texas General Land Office, Railroad Commission of Texas, Texas Water Development Board, STATE OF LOUISIANA, and STATE OF MISSISSIPPI, *Petitioners,* v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, GINA MCCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency, UNITED STATES ARMY CORPS OF ENGINEERS, and JO-ELLEN DARCY, in her official capacity as Assistant Secretary of the Army (Civil Works). *Respondents.*	Case No. 15-60492

PETITION FOR REVIEW

Pursuant to Section 509(b)(1) of the Clean Water Act, 33 U.S.C. § 1369(b)(1), and Federal Rule of Appellate Procedure 15, the State of Texas, Texas Department of Agriculture, Texas Commission on Environmental Quality, Texas Department of Transportation, Texas General Land Office, Railroad Commission of Texas, Texas Water Development Board, State of Louisiana, and State of Mississippi petition the Court for review of the rulemaking titled "Clean Water Rule: Definition of 'Waters of the Unted States,'" promulgated on June 29, 2015, by Respondents United States Environmental Protection Agency and United States Army Corps of Engineers. 80 Fed. Reg. 37,054 (June 29, 2015) ("Final Rule"). A copy of the Final Rule is enclos ed with this filing.

Petitioners file this Petition for Review only out of an abundance of caution, and believe the Petition should be dismissed for lack of jurisdiction. In the Final Rule, EPA and the Corps suggest that a challenge to the Final Rul e may fall within the court of appeals' jurisdiction under 33 U.S.C. § 1369(b)(1). *See* 80 Fed. Reg. at 37,104. Petitioners believe this is clearly incorrect as a matter of law, and that jurisdiction to review the Rule lies with district courts under 28 U.S.C. § 1331. *See Friends of the Everglades v. EPA*, 699 F.3d 1280 (11th Cir. 2012). Nevertheless, Petitioners file this Petition for Review as a protective matter, consistent with established practice. *See Inv. Co. Inst. v. Bd. of Governors of Fed. Reserve*, 551 F.2d1270, 1280 (D.C. Cir 1997) ("If any doubt as to the proper forum exists, careful counsel should file suit in both the court of appeals and the district court or, since there would be no time bar to a proper action in th e district court, bring suit only in the court of appeals."). Petitioners have also filed a complaint in the U.S. District Court for the Southern District of Texas, challenging the Final R ule on similar grounds as those that would be the subject of this Petition for Review.

Dated: July 13, 2015

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

BERNARD L. McNAMEE
Chief of Staff

SCOTT A. KELLER
Solicitor General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

JON NIERMANN
Chief, Environmental Protection Division

/s/ Matthew B. Miller
MATTHEW B. MILLER
Assistant Attorney General
State Bar No. 24074722
matt.miller@texasattorneygeneral.gov

LINDA B. SECORD
Assistant Attorney General
State Bar No. 17973400
linda.secord@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax. (512) 320-0911

Attorneys for the State of Texas

JAMES D. "BUDDY" CALDWELL
Attorney General of Louisiana

TREY PHILIPS
First Assistant Attorney General

/s/ Megan K. Terrell
MEGAN K. TERRELL
Deputy Director – Civil Division
Chief – Environmental Section
Assistant Attorney General
La. Bar Roll No. 29443
Office of the Louisiana Attorney General
1885 N. Third Street
Baton Rouge, Louisiana 70802
Phone: (225) 326-6020
Fax: (225) 326-6099

Attorneys for the State of Louisiana

JIM HOOD
Attorney General of the State of Mississippi

/s/ Mary Jo Woods
MARY JO WOODS
Special Assistant Attorney General
Miss. Bar No. 10468
Mississippi Attorney General's Office
Post Office Box 220
Jackson, Mississippi 39205
Phone: (601) 359-3020
Facsimile: (601) 359-2003
Email: mwood@ago.state.ms.us

Attorneys for the State of Mississippi

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS,
Railroad Commission of Texas, and
Texas Commission on Environmental
Quality,
Petitioners,

v.

UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY, and REGINA
A. MCCARTHY, in her official capacity as
Administrator of the United States
Environmental Protection Agency,
Respondents.

Case No. 16-1257

PETITION FOR REVIEW

In accordance with the Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), 5 U.S.C. § 702, and Federal Rule of Appellate Procedure 15(a), petitioners the State of Texas, the Railroad Commission of Texas, and the Texas Commission on Environmental Quality, hereby petition this Court for review of respondent United States Environmental Protection Agency's final actions entitled: "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," 81 Fed. Reg. 35824. (June 3, 2016), a copy of which is enclosed with this filing (Attachment 1).

This Court has jurisdiction and is a proper venue for this action under 42 U.S.C. § 7607(b)(1).

Dated: July 27, 2016

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

SCOTT KELLER
Solicitor General of Texas

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

CRAIG J. PRITZLAFF
Assistant Attorney General
Court of Appeals – D.C. Circuit - Bar No. 56496
craig.pritzlaff@texasattorneygeneral.gov

MARK A. STEINBACH
Assistant Attorney General
Application to D.C. Circuit pending
mark.steinbach@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS and
THE TEXAS COMMISSION ON
ENVIRONMENTAL QUALITY,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY and
REGINA A. MCCARTHY, Administrator,
United States Environmental Protection Agency

Respondents.

Case No. 15-1494

PETITION FOR REVIEW

In accordance with 5 U.S.C. § 702, 42 U.S.C. § 7607(b)(1), and Federal Rule of Appellate Procedure 15(a), petitioners the State of Texas and the Texas Commission on Environmental Quality hereby petition this Court for review of respondent United States Environmental Protection Agency's final action entitled "National Ambient Air Quality Standards for Ozone," 80 Fed. Reg. 65292 (October 26, 2015), a copy of which is enclosed with this filing. This Court has jurisdiction and is a proper venue for this action under 42 U.S.C. § 7607(b)(1).

Dated: December 22, 2015

Respectfully Submitted,

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

CRAIG J. PRITZLAFF
Deputy Chief, Environmental Protection Division

MATTHEW B. MILLER
Assistant Attorney General

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax (512) 320-0911
matt.miller@texasattorneygeneral.gov

COUNSEL FOR PETITIONERS

**IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT**

STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY,	)	
***Petitioners*,**	)	
v.	)	**Case No. ______________**
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, GINA MCCARTHY, in her official capacity as Administrator of the United States Environmental Protection Agency,	)	
***Respondent*.**	)	

PETITION FOR REVIEW

Pursuant to Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), and Federal Rule of Appellate Procedure 15, the State of Texas and the Texas Commission on Environmental Quality ("TCEQ") petition the Court for review of the Texas-applicable portions of the United States Environmental Protection Agency's ("EPA") final action on rulemaking titled *State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and*

Malfunction, published in the *Federal Register* at 80 Fed. Reg. 33,839 on June 12, 2015, and attached to this petition as Exhibit 1.

Specifically, the State and TCEQ request that the Court review those parts of EPA's Final Rule that apply to the State of Texas, including: 1) EPA's finding under 42 U.S.C. § 7410(k)(5) that four provisions in Texas's approved State Implementation Plan ("SIP") (*i.e.*, 30 Tex. Admin. Code § 101.222(b), (c), (d) and (e), which provide affirmative defenses for certain upset events, unplanned events, and opacity events), "are substantially inadequate to meet [Clean Air Act] requirements"; and 2) EPA's "SIP call with respect to these provisions." 80 Fed. Reg. 33,968–69 (June 12, 2015).

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

JON NIERMANN
Chief, Environmental Protection Division

/s/ *Kellie E. Billings-Ray*
KELLIE E. BILLINGS-RAY
Assistant Attorney General
State Bar No. 24042447
kellie.billings-ray@texasattorneygeneral.gov

Priscilla M. Hubenak
Assistant Attorney General
State Bar No. 10144690
priscilla.hubenak@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax. (512) 457-4638

ATTORNEYS FOR THE STATE OF TEXAS AND THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

In the
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

MICHIGAN ATTORNEY GENERAL BILL SCHUETTE,
on behalf of the PEOPLE OF MICHIGAN,
and the STATES OF ALABAMA, ARIZONA, ARKANSAS,
KANSAS, KENTUCKY, NEBRASKA, NORTH DAKOTA,
OHIO, OKLAHOMA, SOUTH CAROLINA, TEXAS,
WEST VIRGINIA, WISCONSIN, and WYOMING, and
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY,
PUBLIC UTILITY COMMISSION OF TEXAS, and
RAILROAD COMMISSION OF TEXAS,

Petitioners,

v. Case No. 16-1204

UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY,

Respondent.

ORIGINAL

PETITION FOR REVIEW

Pursuant to Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), and Rule 15(a) of the Federal Rules of Appellate Procedure, Fed. R. App. P. 15(a), Michigan Attorney General Bill Schuette, on behalf of the People of Michigan, the States of Alabama, Arizona, Arkansas, Kansas, Kentucky, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Texas, West Virginia, Wisconsin, and Wyoming, and the Texas Commission on Environmental Quality, Public

Utility Commission of Texas, and Railroad Commission of Texas hereby petition for review of the final action of the United States Environmental Protection Agency published in the Federal Register at 81 Fed. Reg. 24,420 (April 25, 2016) and titled "Supplemental Finding That It Is Appropriate and Necessary To Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units."

Respectfully submitted,

Bill Schuette
Attorney General

Aaron D. Lindstrom
Solicitor General

Neil D. Gordon (DC# 436522)
Assistant Attorney General
Counsel of Record
Brian J. Negele
Assistant Attorney General
ENRA Division
525 W. Ottawa Street
P.O. Box 30755
Lansing, MI 48909
Telephone: (517) 373-7540
Facsimile: (517) 373-1610
gordonn1@michigan.gov
negeleb@michigan.gov
Counsel for the People of Michigan

Dated: June 23, 2016

Ken Paxton
Attorney General of Texas

Jeffrey C. Mateer
First Assistant Attorney General

Brantley Starr
Deputy First Assistant Attorney General

James E. Davis
Deputy Attorney General for Civil Litigation

Priscilla M. Hubenak
Chief, Environmental Protection Division

by consent for Ken Paxton

Mary E. Smith
Assistant Attorney General
Mary.Smith@texasattorneygeneral.gov
Office of the Attorney General of Texas
Environmental Protection Division
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Telephone: (512) 475-4041
Facsimile: (512) 320-0911
Counsel for the State of Texas, Texas Commission on Environmental Quality, Public Utility Commission of Texas, and Railroad Commission of Texas

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

STATE OF WEST VIRGINIA,
STATE OF TEXAS,
STATE OF ALABAMA,
STATE OF ARIZONA CORPORATION COMMISSION,
STATE OF ARKANSAS,
STATE OF COLORADO,
STATE OF FLORIDA,
STATE OF GEORGIA,
STATE OF INDIANA,
STATE OF KANSAS,
COMMONWEALTH OF KENTUCKY,
STATE OF LOUISIANA,
STATE OF LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY
ATTORNEY GENERAL BILL SCHUETTE, People of Michigan,
STATE OF MISSOURI,
STATE OF MONTANA,
STATE OF NEBRASKA,
STATE OF NEW JERSEY,
STATE OF NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY,
STATE OF OHIO,
STATE OF SOUTH CAROLINA,
STATE OF SOUTH DAKOTA,
STATE OF UTAH,
STATE OF WISCONSIN, and
STATE OF WYOMING,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,
and REGINA A. MCCARTHY, Administrator,
United States Environmental Protection Agency,

PETITION FOR REVIEW

Case No. 15-1363

ORIGINAL

Respondents.

The States of West Virginia, Texas, Alabama, Arkansas, Colorado, Florida, Georgia, Indiana, Kansas, Louisiana, Michigan, Missouri, Montana, Nebraska, New Jersey, Ohio, South Carolina, South Dakota, Utah, Wisconsin, Wyoming, and the Commonwealth of Kentucky, the Arizona Corporation Commission, the State of Louisiana Department of Environmental Quality, and the State of North Carolina Department of Environmental Quality hereby petition this Court, pursuant to Rule 15(a) of the Federal Rules of Appellate Procedure, Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), and 5 U.S.C. § 702, for review of the final rule of the United States Environmental Protection Agency published in the Federal Register at 80 Fed. Reg. 64,662 (October 23, 2015) and titled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." This Court has jurisdiction, and is a proper venue for this action, under 42 U.S.C. § 7607(b)(1).

Petitioners will show that the final rule is in excess of the agency's statutory authority, goes beyond the bounds set by the United States Constitution, and otherwise is arbitrary, capricious, an abuse of discretion and not in accordance with law. Accordingly, Petitioners ask the Court to hold unlawful and set aside the rule, and to order other such relief as may be appropriate. *See* 42 U.S.C. § 7607(d).

Dated: October 23, 2015

Respectfully submitted,

Patrick Morrisey
Attorney General of West Virginia
Elbert Lin
Solicitor General
Counsel of Record
Misha Tseytlin
General Counsel
J. Zak Ritchie
Assistant Attorney General
State Capitol Building 1, Room 26-E
Tel. (304) 558-2021
Fax (304) 558-0140
Email: elbert.lin@wvago.gov
Counsel for Petitioner State of West Virginia

/s/ Scott A. Keller
Ken Paxton
Attorney General of Texas
Charles E. Roy
First Assistant Attorney General
Bernard L. McNamee II
Chief of Staff
Scott A. Keller
Solicitor General
Counsel of Record
P.O. Box 12548
Austin, Texas 78711-2548
Tel. (512) 936-1700
Email: Scott.Keller@texasattorneygeneral.gov
Counsel for Petitioner State of Texas

ATTACHMENT 3B

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

STATE OF WISCONSIN, *et al.*, **Petitioners,** **v.** **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and Regina A. McCarthy, Administrator, United States Environmental Protection Agency** **Respondents.**	**No. 16-1406 and Consolidated Cases**
STATE OF TEXAS and the TEXAS COMMISSION ON ENVIRONMENTAL QUALITY **Petitioners,** **v.** **UNITED STATES ENRIRONMENTAL AGENCY,** **Respondent.**	**No 16-1428**

PETITIONERS' NON-BINDING STATEMENT OF ISSUES

Petitioners, the State of Texas, and the Texas Commission on Environmental Quality, challenge the legality of the United States Environmental Protection Agency ("EPA") rulemaking entitled "Cross-State Air Pollution Rule Update for the

2008 Ozone NAAQS; Final Rule," published at 81 Fed. Reg. 74,504 (October 26, 2016) ("Final Rule"), and respectfully submit this preliminary and non-binding statement of issues:

1. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA failed to give independent significance to the distinct and separate requirements of Section 110(a)(2)(D)(i)(I) of the Clean Air Act, 42 U.S.C. § 7410(a)(2)(D)(i)(I).

2. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA proposed a federal implementation plan for States before the EPA acted on state implementation plans, which States, such as Texas, previously submitted to implement § 7410(a)(2)(D)(i)(I).

3. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because the EPA fails to properly consider actual monitoring data and trends, and impermissibly relies on a model that is flawed with inappropriate assumptions and conditions.

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civ. Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF
Assistant Attorney General
D.C. Circuit Bar No. 56496
craig.pritzlaff@oag.texas.gov

LINDA B. SECORD
Assistant Attorney General
D.C. Circuit application process underway
linda.secord@oag.texas.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY, Petitioners, v. ENVIRONMENTAL PROTECTION AGENCY and E. Scott Pruitt, in his official capacity as Administrator of the United States Environmental Protection Agency, Respondents.	No. 17-1021 (and consolidated cases)

PETITIONERS' NON-BINDING STATEMENT OF ISSUES

Petitioners, the State of Texas and the Texas Commission on Environmental Quality, challenge the legality of the United States Environmental Protection Agency ("EPA") rulemaking entitled "Protection of Visibility: Amendments to Requirements for State Plans," published at 82 Fed. Reg. 3,078 (Jan. 10, 2017) ("Final Rule"), and respectfully submit this preliminary and non-binding statement of issues:

1. Section 169A(d) of the Clean Air Act, 42 U.S.C. § 7491(d), provides that States shall consult and consider the conclusions and recommendations of a federal land manager ("FLM") when accepting public comment on state

implementation plans prepared to address the regional haze and visibility requirements of the Clean Air Act. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because it converts the statutory discretion States have in considering the conclusions of a federal land manager into a mandatory requirement that States must respond through costly formal revision of their regional haze state implementation plan. In particular, the Final Rule improperly mandates that States must revise their regional plans in response to a federal land manager's certification of reasonably attributable visibility impairment for a Class I air quality area listed pursuant to 42 U.S.C. § 7491(a).

2. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because it fails to properly address the impacts of international emissions of pollutants on visibility in Class 1 areas in the United States, especially those areas along or near an international border. In particular, the Final Rule fails to provide approved methodologies for states to address impacts from international emissions of pollutants and natural haze from the determination of reasonable progress toward reducing man-made pollution sources that effect visibility in Class I air quality areas.

3. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA did not properly consider the disproportionate costs imposed upon States to meet non-health based visibility goals,

which are more burdensome and costly to meet than health-based national ambient air quality standards. The burdens and costs to meet such goals are wholly disproportionate to any net benefit sought.

Respectfully submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF
Assistant Attorney General
D.C. Circuit – Bar No. 56496
craig.pritzlaff@oag.texas.gov

LINDA B. SECORD
Assistant Attorney General
D.C. Circuit – Bar No. 60183
linda.secord@oag.texas.gov

MARK A. STEINBACH
Assistant Attorney General
D.C. Circuit – Bar No. 59880
mark.steinbach@oag.texas.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512)463-2012
Fax: (512) 320-0911

Counsel for Petitioners

CERTIFICATE OF SERVICE

Pursuant to Rule 25 of the Federal Rules of Appellate Procedure, and D.C. Circuit Rule 25, I hereby certify that on March 31, 2017, I electronically filed the foregoing document with the Clerk of the Court using the CM/ECF System, which will send notice of such filing to all CM/ECF registered counsel in this case, and all consolidated cases.

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS, et al., *Petitioners*, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al. *Respondents*.	Case No. 16-1257 (Consolidated with Nos. 16-1242, 16-1262; 16-1263; 16-1264; 16-1266, 16-1267; 16-1269; and 16-1270)

PETITIONERS' NON-BINDING STATEMENT OF ISSUES

Petitioners, the State of Texas, the Railroad Commission of Texas, and the Texas Commission on Environmental Quality, challenge the legality of the United States Environmental Protection Agency ("EPA") rulemaking entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Final Rule"), and respectfully submit this preliminary and non-binding statement of issues:

1. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA included facility source categories not originally included or contemplated in the listing of source categories as previously determined by the EPA under Section 111(b) of the Clean Air Act ("CAA"), 42 U.S.C. § 7411(b);

2. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA did not prepare an independent

endangerment finding for methane, which is used in the Final Rule as an improper surrogate for all other "greenhouse gases" included in the Final Rule;

3. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because the EPA did not prepare an independent endangerment finding for the oil and gas source category to establish standards of performance for methane and other greenhouse gas emissions from such sources in accordance with Sections 111(b) and 111(f) of the CAA, 42 U.S.C. §§ 7411(b) and 7411(f), and, therefore, the EPA failed to properly evaluate the scientific evidence concerning the effect of greenhouse gas emissions from the oil and gas source category, in particular methane, and otherwise disregarded data and analyses that conflicts with its decision to create standards for emissions of greenhouse gases from oil and gas facilities; and

4. The Final Rule is arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because the EPA did not base its cost/benefit estimates on reasoned bases and analyses, and, therefore, the EPA failed to properly consider the complete regulatory burden of the Final Rule on Texas' regulatory agencies and the oil and gas industry in Texas.

Respectfully Submitted,

KEN PAXTON
Attorney General of Texas

JEFFREY C. MATEER
First Assistant Attorney General

BRANTLEY STARR
Deputy First Assistant Attorney General

SCOTT KELLER
Solicitor General of Texas

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF
Assistant Attorney General
Court of Appeals – D.C. Circuit - Bar No. 56496
craig.pritzlaff@texasattorneygeneral.gov

MARK A. STEINBACH
Assistant Attorney General
Court of Appeals – D.C. Circuit - Bar No. 59880
mark.steinbach@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC 066
Austin, Texas 78711-2548
Tel: (512) 463-2012
Fax: (512) 320-0911

Counsel for Petitioners

CERTIFICATE OF SERVICE

Pursuant to Rule 25 of the Federal Rules of Appellate Procedure, I hereby certify that on August 29, 2016, I served the foregoing document on all registered counsel in this case, and all consolidated cases, through the Court's CM/ECF system.

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF TEXAS, et al.,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.

Respondents.

Case No. 15-1494
(Consolidated with
Nos. 15-1385, 15-1392,
15-1490, and 15-1491)

PETITIONERS' NON-BINDING STATEMENT OF ISSUES

Petitioners, the State of Texas and the Texas Commission on Environmental Quality, challenge the legality of the final agency rule entitled "National Ambient Air Quality Standards for Ozone," published at 80 Fed. Reg. 65292 (Oct. 26, 2015), and respectfully submit this preliminary and non-binding statement of issues:

1. Whether EPA's revision of the national ambient air qualit y standard for ozone ("ozone NAAQS") was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the Clean Air Act ("CAA") or any other laws;

2. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law because EPA failed to consider the effects that an unnecessarily stringent standard would have on Texas's social, economic, and sovereign interests;

3. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because EPA failed to properly evaluate the scientific evidence and disregarded data and analyses that conflicted with its decision to lower the ozone NAAQS from 75 parts per billion ("ppb") to 70 ppb;

4. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because EPA disregarded evidence showing that lowering the ozone NAAQS was unnecessary to protect human health;

5. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because EPA ignored analyses from the Texas Commission on Environmental Quality and other entities that show no difference in ozone-inhaled dosage between 70 and 75 ppb;

6. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because EPA failed to consider background levels of ozone, including those caused by mobile sources, stratospheric intrusion, bordering states, the Texas-Mexico border, as well as exceptional events and other factors over which Texas has no control;

7. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because EPA set a standard impossible for Texas to attain;

8. Whether EPA's revision of the ozone NAAQS was arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with the CAA because Texas is still devoting resources and working toward attaining the 2008 ozone NAAQS, making EPA's action premature and unnecessary; and

9. EPA's revision of the ozone NAAQS forms part of larger, comprehensive framework of recent rules promulgated by the EPA, some of which target the same underlying air pollutants at issue in the ozone NAAQS. EPA's other rule promulgations are the subject of meritorious challenges in this and other circuits. EPA has failed to consider the comprehensive social, economic, and health effects of these other rule changes, if implemented, and whether those rules will achieve the social, economic, and health effects intended in *this* promulgation—therefore subjecting Texas and other entities to duplicative and unnecessary expenditures.

Respectfully Submitted,

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division
Assistant Attorney General
priscilla.hubenak@texasattorneygeneral.gov

/s/ Matthew B. Miller
MATTHEW B. MILLER
Assistant Attorney General
matt.miller@texasattorneygeneral.gov
Lead Counsel

CRAIG J. PRITZLAFF
Assistant Attorney General
craig.pritzlaff@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax (512) 320-0911

COUNSEL FOR PETITIONERS,
STATE OF TEXAS AND TEXAS COMMISSION ON
ENVIRONMENTAL QUALITY

CERTIFICATE OF SERVICE

Pursuant to Rule 25 of the Federal Rules of Appellate Procedure, I hereby certify that on February 3, 2016, I served the foregoing Petitioners' Non-Binding Statement of Issues on all registered counsel in this case, and all consolidated cases, through the Court's CM / ECF system.

/s/ Craig J. Pritzlaff
CRAIG J. PRITZLAFF
Assistant Attorney General

**IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT**

SOUTHEASTERN LEGAL FOUNDATION, INC. *Petitioner*, **v.** **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al*.,** *Respondents*.	**Case No. 15-1166**
STATE OF TEXAS and TEXAS COMMISSION ON ENVIRONMENTAL QUALITY, *Petitioners*, **v.** **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,** *Respondents*.	**Case No. 15-1308 (consolidated with No. 15-1166 and other consolidated cases)**

STATE OF TEXAS AND TEXAS COMMISSION ON ENVIRONMENTAL QUALITY'S NONBINDING STATEMENT OF ISSUES

The State of Texas and the Texas Commission on Environmental Quality (collectively, the State of Texas), the petitioners in Case No. 15-1308 (consolidated under Lead Case No. 15 -1166), submit this nonbinding statement of issues in this proceeding challengin g the final action of the respondent United States Environmental Protection Agency (EPA) entitled *State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown, and Malfunction*, 80 Fed. Reg. 33,839 (June 12, 2015) (Final Rule).

The following is a nonexclusive and nonbinding list of issues that the State of Texas may raise in this case:

1. Whether EPA's "substantial inadequacy" finding and "SIP Call" of Texas's state implementation plan (SIP) based on Texas's inclusion of affirmative defenses for maintenance, startup, and shutdown activities is unlawful and arbitrary and capricious because EPA failed to consider the language of 30 Texas Administrative Code § 101.222(f), providing that Texas's affirmative defense "applies only to violations of state implementation plan requirements [and] . . . cannot apply to violations of federally promulgated performance or technology based standards, such as those found in 40 Code of Federal Regulations Parts 60, 61, and 63";

2. Whether EPA's substantial inadequacy finding and SIP Call with regard to Texas's affirmative defense provisions is unlawful and arbitrary and

capricious based on the undisputed agency record that shows that Texas's affirmative defenses do not negate United States District Court jurisdiction;

3. Whether EPA must identify a specific provision of the Clean Air Act that Texas's affirmative defense provisions violate as a prerequisite to issuing a SIP Call;

4. Whether 42 U.S.C. § 7410(k)(5) permits EPA to issue a SIP Call when the only basis for that SIP Call is that a SIP provision is inconsistent with a newly issued EPA policy statement;

5. Whether EPA has provided any rational basis to determine that previously approved affirmative defenses for periods of maintenance, startup, and shutdown activities are now substantially inadequate to comply with the Clean Air Act;

6. With regard to Texas's SIP, whether EPA failed to comply with the statutory procedural requirements under 42 U.S.C. § 7607(d)—to include the requirement to provide an explanation of the "major legal interpretations and policy considerations underlying the proposed rule";

7. Whether EPA's revised policy disallowing the use of exemptions and affirmative defenses for periods of maintenance, startup, and shutdown activities is contrary to law, of any legal effect, entitled to any deference, or even enforceable;

8. Whether EPA's substantial inadequacy finding and SIP Call of Texas's SIP is unlawful and arbitrary and capricious because EPA's only stated rationale for its decision (that Texas's affirmative defense provisions "alter or eliminate the jurisdiction of federal courts to assess penalties for violations of SIP emission limits," 79 Fed. Reg. 55,945) is barred by principles of res judicata, claim preclusion, and issue preclusion by the Fifth Circuit Court of Appeals decision in Luminant Generation. *Luminant Generation Co. LLC v. Envtl. Prot. Agency*, 714 F.3d 841, 853 n. 9 (5th Cir. 2013) (holding that the same Texas affirmative defenses at issue here do not "negate the district court's jurisdiction to assess civil penalties using the criteria outlined in section 7413(e), or the state permitting authority's power to recover civil penalties. . . . ");

9. Whether EPA's substantial inadequacy finding and SIP Call as to Texas's maintenance, startup, and shutdown affirmative defenses is unlawful and arbitrary and capricious because EPA's action directly contravenes the lawfully issued mandate in Luminant Generation. *Id*;

10. Whether EPA failed to meet its burden under 42 U.S.C. § 7410(k)(5) to demonstrate that the inclusion of affirmative defenses for maintenance, startup, and shutdown activities in Texas's SIP is substantially inadequate to comply with the provisions of the Clean Air Act —particularly in light of the *Luminant Generation*

decision, holding that the affirmative defense provisions in Texas's SIP were compliant with the Clean Air Act. *Id*;

11. Whether EPA's disregard of the *Luminant Generation* decision is unlawful under this Court's decision in *NEDACAP v. EPA* and in light of EPA's regional consistency regulations. *Nat'l Envtl. Dev. Ass'ns Clean Air Project v. Envtl. Prot. Agency*, 752 F.3d 999 (D.C. Cir. 2014);

12. Whether EPA may use venue provisions under 42 U.S.C. § 7607(b)(1) and a self-declaration of "nationwide scope or effect" finding to circumvent binding Fifth Circuit Court of Appeals precedent; and

13. Whether EPA improperly relied on this Court's opinion in *NRDC v. EPA* to find Texas's affirmative defense provisions to be invalid —ignoring a Fifth Circuit Court of Appeals finding to the contrary *Compare Natural Res. Def. Council v. Envtl. Prot. Agency*, 749 F.3d 1055 (D.C. Cir. 2014), *with Luminant Generation*, 714 F.3d 841, 853 n. 9.

The State of Texas Petitioners submit these issues as a nonbinding statement only and reserve the right to raise other issues in merits briefing before the Court.

Respectfully submitted,

/s/ *Kellie E. Billings-Ray*
Kellie E. Billings-Ray

Counsel for the State of Texas and the Texas Commission on Environmental Quality:

KEN PAXTON
Attorney General of Texas

CHARLES E. ROY
First Assistant Attorney General

JAMES E. DAVIS
Deputy Attorney General for Civil Litigation

PRISCILLA M. HUBENAK
Chief, Environmental Protection Division

Kellie E. Billings-Ray
Assistant Attorney General
kellie.billings-ray@texasattorneygeneral.gov

OFFICE OF THE ATTORNEY GENERAL OF TEXAS
ENVIRONMENTAL PROTECTION DIVISION
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Tel. (512) 463-2012
Fax. (512) 457-4638

In the
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

MICHIGAN ATTORNEY GENERAL
BILL SCHUETTE, on behalf of the
PEOPLE OF MICHIGAN,
and the STATES OF ALABAMA,
ARIZONA, ARKANSAS, KANSAS,
KENTUCKY, NEBRASKA,
NORTH DAKOTA, OHIO, OKLAHOMA,
SOUTH CAROLINA, TEXAS,
WEST VIRGINIA, WISCONSIN, and
WYOMING, and TEXAS COMMISSION
ON ENVIRONMENTAL QUALITY,
PUBLIC UTILITY COMMISSION OF TEXAS,
and RAILROAD COMMISSION OF TEXAS,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL
PROTECTION AGENCY,

Respondent.

Case No. 16-1204/
Lead Case No. 16-1127
(and consolidated cases)

PETITIONERS' NON-BINDING STATEMENT OF ISSUES TO BE RAISED

Pursuant to the Court's Order of June 30, 2016, Petitioners in Case No. 16-1204 hereby submit the following non-binding statement of issues to be raised:

1. Whether the final action of the United States Environmental Protection Agency ("EPA") published in the Federal Register at 81 Fed.

Reg. 24,420 (April 25, 2016) and titled "Supplemental Finding That It Is Appropriate and Necessary To Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units" ("Supplement Finding") violates Section 112(n)(1)(A) of Clean Air Act, 42 U.S.C. § 7412(n)(1)(A), the Supreme Court's decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), or is otherwise arbitrary, capricious, or unlawful because it is based on reductions in the emission of air pollutants that are not hazardous air pollutants and that are irrelevant to a finding of whether it is appropriate and necessary to regulate hazardous air pollutants under Section 112 of the Clean Air Act.

2. Whether EPA's Supplemental Finding violates Section 112(n)(1)(A) of the Clean Air Act, the Supreme Court's decision in *Michigan v. EPA*, or is otherwise arbitrary, capricious, or unlawful because EPA failed to balance the relevant costs and benefits.

3. Whether EPA's Supplemental Finding violates Section 112(n)(1)(A) of the Clean Air Act, the Supreme Court's decision in *Michigan v. EPA*, or is otherwise arbitrary, capricious, or unlawful because EPA failed to demonstrate that concentrations of particulate matter smaller than 2.5 micrometers in diameter ($PM_{2.5}$) in the ambient

air below the National Ambient Air Quality Standards for $PM_{2.5}$ provide public health benefits.

Respectfully submitted,

Bill Schuette
Attorney General

Aaron D. Lindstrom
Solicitor General

/s/ Neil D. Gordon
Neil D. Gordon (DC# 436522)
Assistant Attorney General
Counsel of Record
Brian J. Negele
Assistant Attorney General
ENRA Division
525 W. Ottawa Street
P.O. Box 30755
Lansing, MI 48909
Telephone: (517) 373-7540
Facsimile: (517) 373-1610
gordonn1@michigan.gov
negeleb@michigan.gov
Counsel for the People of Michigan

Dated: July 29, 2016

Ken Paxton
Attorney General of Texas

Jeffrey C. Mateer
First Assistant Attorney General

Brantley Starr
Deputy First Assistant Attorney General

James E. Davis
Deputy Attorney General for Civil Litigation

Priscilla M. Hubenak
Chief, Environmental Protection Division

/s/ *Mary E. Smith*
Mary E. Smith
Assistant Attorney General
Mary.Smith@texasattorneygeneral.gov
Office of the Attorney General of Texas
Environmental Protection Division
P.O. Box 12548, MC-066
Austin, Texas 78711-2548
Telephone: (512) 475-4041
Facsimile: (512) 320-0911
Counsel for the State of Texas, Texas Commission on Environmental Quality, Public Utility Commission of Texas, and Railroad Commission of Texas

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al*., Respondents.	Case No. 15-1363 (and consolidated cases)

PETITIONERS' NONBINDING STATEMENT OF THE ISSUES TO BE RAISED

Pursuant to this Court's o rder dated November 30, 2015, *see* ECF 1585786, Petitioners in lead case No. 15-1363 and consolidated case No. 15-1409 submit the following nonbinding statement of issues to be raised in this proceeding reviewing the final rule of the United States Environmental Protection Agency (EPA) entitled, "Carbon Pollution E mission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (Oct. 23, 2015) ("Rule"):

Core Legal Issues

1. Whether the Rule, which regulates existing power plants under CAA § 111(d), 42 U.S.C. § 7411(d), is unlawful because EPA has regulated the same power plants under CAA § 112, 42 U.S.C. § 7412.

2. Whether EPA has the authority to force States to transform their energy economies to favor only certain sources of electricity, under the guise of regulating power plants under CAA § 111(d), 42 U.S.C. § 7411(d).

3. Whether EPA's authority is limited to promulgating regulations to establish a "procedure" under which States submit implementation plans in which the States establish "standards of performance" for existing sources under CAA § 111(d), 42 U.S.C. § 7411(d)(1).

4. Whether EPA's threat that it will seize control over the States' energy economies if they do not submit state plans violates the States' rights under the Tenth Amendment and the Federal Power Act, 16 U.S.C. § 824(a).

Programmatic or Record-Based Issues

1. Whether the Rule is unlawful because it is not a logical outgrowth of the proposed rule.

2. Whether the Rule's exclusion of certain categories of sources of zero emission energy and sources of energy efficiency from the special incentives created under the Clean Energy Incentive Program is unlawful.

3. Whether the Rule allowing cap and trade as a compliance option for meeting a "performance standard" is unlawful.

4. Whether the Rule requiring State Plans to regulate new, existing, or modified sources through means which include leakage provisions, set asides, and new source complements is unlawful.

5. Whether the Rule allowing States that choose a mass-based compliance plan to adopt a "state measures approach" and denying this option to States that choose a rate-based compliance plan is unlawful.

6. Whether the Rule's limitations on trading between rate-based and mass-based States are unlawful.

7. Whether the Rule is unlawful and violates due process because fundamental elements critical to the Rule are uncertain or unknown, including technical issues relating to emission rate credits (ERCs), or are currently non-final agency action, including the model trading rules and the federal plan

8. Whether the Rule's treatment of existing nuclear energy sources in Arkansas, particularly EPA's refusal to provide clean energy credit for Entergy's Arkansas Nuclear One power plant, is unlawful.

9. Whether EPA's failure to consider Florida's unique peninsular geography and the fact that only two States border Florida, thus limiting Florida's power transfer opportunities, is unlawful.

10. Whether EPA's failure to allow Florida to receive credit for decreases in emissions already achieved is unlawful.

11. Whether EPA's assumptions regarding the extent of renewable generation that could be developed in Florida and used to offset emissions from fossil fuel sources without accounting for intricacies and constraints on purchasing renewable energy under Florida law is unlawful.

12. Whether the Rule's failure to provide a method to account meaningfully for over three billion dollars in stranded investments made by Kansas utilities to install criteria pollutant control equipment on power plants in that State, is unlawful.

13. Whether the Rule's failure to provide compliance credit or emission rate credits for New Jersey's pre-2013, multi-billion dollar ratepayer investments in renewable energy, energy efficiency, and nuclear construction and uprates is unlawful.

14. Whether EPA has the authority to require New Jersey, an energy deregulated State that has chosen to eliminate the traditional retail monopoly structure which electric public utilities had previously held in th is State for electric power generation and supply services, to enact a new legislative scheme so that New Jersey can exercise the authority over electric generation facilities that is required to comply with the Clean Power Plan.

15. Whether the Rule's failure to significantly account for the cost of achieving emissions reductions in New Jersey is unlawful.

16. Whether the Rule's effect of severely limiting fuel diversity in New Jersey, thereby presenting significant reliability and cost concerns, especially during bouts of extreme weather, is unlawful.

17. Whether the Rule unlawfully threatens the reliability of electric supply in the South Dakota because the only coal -fired power plant and the only natural gas-fired power plant in the State lack common ownership, have different regional transmission operators, and do not share a common customer base.

18. Whether the Rule unlawfully forces Texas to redesign the Electric Reliability Council of Texas ("ERCOT"), which is the only Independent System Operator in the continental United States that operates an electricity market that is wholly contained within one State and is not synchronously interconnected with the rest of the country, and which has otherwise been a vibrant and extremely successful competitive wholesale and reta il electricity market for Texas.

19. Whether Texas is being unlawfully punished by the Rule as a first mover in the area of wind energy because, under the Rule, none of the renewable energy installed prior to January 6, 2013 (or capacity upgrades to existing renewable energy completed prior to that date) can be used by generators or the State to demonstrate compliance with the Rule.

20. Whether the Rule unlawfully applied a 4.3% heat rate improvement to Wisconsin steam power plants.

21. Whether the Rule unlawfully failed to consider biomass energy in developing the Wisconsin emission standard.

22. Whether EPA unlawfully failed to consider the impact of the Rule throughout Wyoming on the greater sage grouse and other sensitive species.

Dated: December 18, 2015

Respectfully submitted,

/s/ Elbert Lin

Patrick Morrisey
Attorney General of West Virginia
Elbert Lin
Solicitor General
Counsel of Record
J. Zak Ritchie
Assistant Attorney General
State Capitol Building 1, Room 26-E
Tel. (304) 558-2021
Fax (304) 558-0140
Email: elbert.lin@wvago.gov
Counsel for Petitioner State of West Virginia

/s/ Scott A. Keller

Ken Paxton
Attorney General of Texas
Charles E. Roy
First Assistant Attorney General
Scott A. Keller
Solicitor General
Counsel of Record
P.O. Box 12548
Austin, Texas 78711-2548
Tel. (512) 936-1700
Email:
Scott.Keller@texasattorneygeneral.gov
Counsel for Petitioner State of Texas

/s/ Andrew Brasher

Luther Strange
Attorney General of Alabama
Andrew Brasher
Solicitor General
Counsel of Record
501 Washington Ave.
Montgomery, AL 36130

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NORTH DAKOTA, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*, Respondents.	Case No. 15-1381 (and consolidated cases)

PETITIONERS' NONBINDING STATEMENT OF THE ISSUES TO BE RAISED

Pursuant to this Court's order dated November 6, 2015, *see* ECF 1582440, Petitioners in case No. 15-1399 (consolidated with case No. 15-1381) submit the following nonbinding statement of issues to be raised in this proceeding:

1. Whether EPA's inclusion of carbon capture and storage (CCS) as part of the "best system of emission reduction" is improper because EPA fails to meet its burden to show that CCS is an "adequately demonstrated" technology as required by Clean Air Act Section 111(b), 42 U.S.C. § 7411.

2. Whether EPA failed to meet its burden to show that CCS is adequately demonstrated, because EPA improperly characterized the "adequately demonstrated" legal standard, as set out by Clean Air Act Section 111(b), 42

U.S.C. § 7411, as requiring merely a showing of the technology's "technical feasibility."

3. Whether EPA's inclusion of CCS as part of the "best system of emission reduction" is improper because EPA failed to meet its burden to show that CCS is the "best system" considering costs as required by Clean Air Act Section 111(b), 42 U.S.C. § 7411.

4. Whether EPA has failed to demonstrate that an emission standard of 1,400 lbs. CO_2/MWh, which effectively mandates that affected sources install CCS, is achievable as required by Clean Air Act Section 111(b), 42 U.S.C. § 7411.

5. Whether EPA violated the Energy Policy Act of 2005 by impermissibly considering government-funded technologies from facilities awarded either Clean Coal Power Initiative funding, *see* 42 U.S.C. § 15962, or Section 48A tax credits, *see* 26 U.S.C. § 48A, as evidence that CCS is an adequately demonstrated technology for purposes of Clean Air Act Section 111(b), 42 U.S.C. § 7411.

6. Whether EPA's decision to implement stringent new source performance standards is arbitrary and capricious because EPA's rule will, by EPA's admission, result in negligible CO_2 emission reductions.

7. Whether EPA failed to properly consider whether CO_2 emissions from new fossil fuel -fired power plants are "reasonably . . . anticipated to endanger public health or welfare" as required for EPA to regulate under Clean Air Act § 111(b), 42 U.S.C. § 7411.

8. Whether EPA's failure to adequately address infrastructure and carbon dioxide transportation costs in States without storage capacity violates the Administrative Procedures Act, 5 U.S. Code § 701 *et seq*.

Dated: December 7, 2015

Respectfully submitted,

/s/ Elbert Lin

Patrick Morrisey
Attorney General of West Virginia
Elbert Lin
Solicitor General
Counsel of Record
J. Zak Ritchie
Assistant Attorney General
State Capitol Building 1, Room 26-E
Tel. (304) 558-2021
Fax (304) 558-0140
Email: elbert.lin@wvago.gov
Counsel for Petitioner State of West Virginia

/s/ Andrew Brasher

Luther Strange
Attorney General of Alabama
Andrew Brasher
Solicitor General
Counsel of Record
501 Washington Ave.
Montgomery, AL 36130

James Emory Smith, Jr.
Deputy Solicitor General
Counsel of Record
P.O. Box 11549
Columbia, SC 29211
Tel. (803) 734-3680
Fax (803) 734-3677
Email: ESmith@scag.gov
Counsel for Petitioner State of South Carolina

/s/ Steven R. Blair
Marty J. Jackley
Attorney General of South Dakota
Steven R. Blair
Assistant Attorney General
Counsel of Record
1302 E. Highway 14, Suite 1
Pierre, SD 57501
Tel. (605) 773-3215
Email: steven.blair@state.sd.us
Counsel for Petitioner State of South Dakota

/s/ Scott A. Keller
Ken Paxton
Attorney General of Texas
Charles E. Roy
First Assistant Attorney General
Bernard L. McNamee II
Chief of Staff
Scott A. Keller
Solicitor General
Counsel of Record
P.O. Box 12548
Austin, Texas 78711-2548
Tel. (512) 936-1700
Email:
Scott.Keller@texasattorneygeneral.gov
Counsel for Petitioner State of Texas

From: Loving, Shanita
Location: WJC-N 5400 + Video with OAQPS + Ex. 6 - Personal Privacy Participant Code: Ex. 6 - Personal Privacy
Importance: Normal
Subject: NSR Improvement
Start Date/Time: Thur 11/30/2017 4:00:00 PM
End Date/Time: Thur 11/30/2017 4:45:00 PM
Wehrum Meeting Request_ NSR Improvement.docx

To: Wehrum, Bill; Harlow, David; Gunasekara, Mandy; Lewis, Josh; Page, Steve; Koerber, Mike; Harnett, Bill; Wood, Anna; Kornylak, Vera; Santiago, Juan; Wayland, Richard; Dunham, Sarah; Harvey, Reid; Krieger, Jackie; Vetter, Cheryl; Rao, Raj
Cc: Alston, Lala; Johnson, Yvonnew; Long, Pam

To: Benjamin, Lynorae[benjamin.lynorae@epa.gov]
Cc: Johnson, Yvonne W[johnson.yvonnew@epa.gov]
Sent: Fri 10/27/2017 8:33:27 PM
Subject: FW: latest version of SESARM 2017 Fall _wTPs
SESARM 2017 Fall _wTPs_oct 24+Final EO Slides.pptx

Hi Lynorae, attached is a draft of my slides which I still need to look at and

From: Kornylak, Vera S.
Sent: Friday, October 27, 2017 8:59 AM
To: Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>; Wood, Anna <Wood.Anna@epa.gov>
Subject: RE: latest version of SESARM 2017 Fall _wTPs

Here are the final slides – I added a slide and edited a few on the EO section.

Vera

Vera Kornylak || Senior Policy Advisor

Air Quality Policy Division || OAQPS

919-541-4067 || kornylak.vera@epa.gov

From: Johnson, Yvonne W
Sent: Thursday, October 26, 2017 5:58 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Cc: Kornylak, Vera S. <Kornylak.Vera@epa.gov>
Subject: latest version of SESARM 2017 Fall _wTPs

Here is the latest version of the SESARM slides which incorporate Mike's comments sent on 10/25. I will let you all decide if you take any of the EO slides out (I added all that Vera sent) and she is planning to send one more.

From: Clint Woods
Location: Call-In Number: 701-Ex. 6 - Personal Privacy Paccode: Ex. 6 - Personal Privacy
Importance: Normal
Subject: EPA - AAPCA Call on Permitting (Hosted by Permitting & NSR Committee)
Start Date/Time: Wed 8/30/2017 7:00:00 PM
End Date/Time: Wed 8/30/2017 8:00:00 PM
AAPCA Permitting Reform Call Agenda and Key Agency Issues 8-29-2017.pdf

;;;
8/29 update – Below and attached (PDF) is our proposed agenda for the August 30 call with AAPCA's Permitting/NSR Committee

AAPCA Member Call with U.S. EPA on Interagency Permitting Reforms
Hosted by Permitting/NSR Committee
Wednesday, August 30, 3:00 – 4:00 PM Eastern
Call-in information: 701-801-1211; Passcode: 867-434-429#

Proposed Agenda:

1. **Welcome / Roll Call**

2. **U.S. EPA Updates on Interagency Permitting Reforms** (*see background information at bottom of agenda)

3. **Key AAPCA Member Issues Raised in Recent Comments** (most of these comments are taken from AAPCA July 2017 report, *The State of Regulatory Reform: Navigating State Perspectives on Clean Air Act Regulations Under Executive Order 13777*)

Title V Review / Petitions Process

- Sample comment: "Responses to a review of a proposed permit that deviates from the Act leads to uncertainty to the public, the State authority, and the applicant as to where the permit stands and, specifically, if the permit can be issued without threat from EPA veto." – North Carolina DAQ, comments on U.S. EPA's Regulatory Reform, Attachment (pg. 33)
- AAPCA member comments on U.S. EPA's proposed "Revisions to the Title V Permitting Program Regulations to Improve the Petitions Process": Alabama DEM; Arkansas DEQ; Georgia EPD; Nevada DEP; North Carolina DEQ; South Carolina DHEC; Texas CEQ; Virginia DEQ; Wyoming DEQ
- Comments on U.S. EPA's Regulatory Reform: AAPCA, pg. 4; Georgia EPD, pg. 3; North Carolina DAQ, pg. 33; Ohio EPA, pg. 3

Unimplemented Recommendations from 2004 – 2006 Title V Task Force

- Sample comment: "In 2004, the Clean Air Act Advisory Committee (CAAAC) established a Task Force on Title V Implementation Experience…. U.S. EPA should examine this report and move forward with recommendations to provide the much needed improvement to the Title V permit system" – Ohio EPA, comments on U.S. EPA's Regulatory Reform, pg. 3
- Report: Title V Task Force, *Final Report to the Clean Air Act Advisory Committee on the Title V Implementation Experience*, April 2006.

Prevention of Significant Deterioration (PSD) permit review

- Sample comment: "Currently, Regional offices are reviewing each PSD permit application processed by the State. Typically, comments and suggestions from the region do not result in any modification of the proposed permit. Reviewing and responding to these minor comments and suggestions requires extra time from the permitting staff and often unnecessarily holds up timely issuance of the permits." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 6

Prevention of Significant Deterioration (PSD) modeling review

- Sample comment: "EPA Regional staff typically review each PSD modeling review. Often, the staff modelers are required to spend significant time in discussion with EPA regarding the modeling review or addressing comments, yet significant changes rarely result from these discussions." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 7

New Source Review (NSR) permitting

- Sample comment: "Specific suggestions to adjust NSR permitting include: removal of volatile organic compound (VOC) requirements in areas with oxides of nitrogen limits under New Source Review (NSR); modifications to PSD and NSR that consider environmentally beneficial projects; and providing a clean unit exemption." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 7

Title V Permitting Requirements for Air Curtain Incinerators/Destructors

- Sample comment: "Regulation with unnecessarily burdensome requirements for owners/operators." – AAPCA, , pg. 4
- Other relevant comments: Arizona DEQ, pg. 1; Georgia EPD, pg. 1 – 2; Maine DEP, pg. 1, 3-5; North Carolina DAQ, pg. 6-7; South Carolina DHEC, pg. 2 – 3; ECOS, pg. 2; NESCAUM, pg. 2

Title V permitting requirements, as found in 40 CFR 70.3 and the National Emissions Standards for Hazardous Air Pollutants for Source Categories (40 CFR 63)

- Sample comment: "Overly burdensome and costly for area sources that are required to obtain and maintain Title V operating permits." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 4
- Other relevant comments: Arizona DEQ, Attachment, pg. 2; Arkansas DEQ, pg. 9; Maine DEP, pg. 17; Nevada DEP, pg. 2; South Carolina DHEC, pg. 2 – 3

Title V Annual Compliance Certifications

- Sample comment: "Title V Annual Compliance Certifications required by 40 CFR 70.6(c) are redundant to the reporting requirements contained elsewhere in the permit and unnecessarily burdensome. EPD spends approximately 1,000 staff hours annually reviewing the certifications." – Georgia EPD, comments on U.S. EPA's Regulatory Reform, pg. 3

Revisions to the Public Notice Provisions in Clean Air Act Permitting Programs

- Sample comment: "Air agencies provided comment on this proposal, and there may be other areas in which EPA should explore electronic notice options." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 4
- See AAPCA member comments on the proposed revisions: Georgia EPD; Kentucky DAQ; Ohio EPA; South Carolina DHEC; Texas CEQ; Virginia DEQ; Wyoming DEQ

"Once In, Always In" Policy for Major Source Maximum Available Control Technology Standards

- Sample comment: "The current policy requires sources that are subject to a major source MACT to always be subject to that MACT standard, even if their emissions are later reduced below major source levels of HAPs, limiting the incentive for industry to reduce emissions or find alternative materials." – AAPCA, comments on U.S. EPA's Regulatory Reform, pg. 4

- Other relevant comments: Arizona DEQ, Attachment (pg. 1); Georgia EPD, pg. 1; Maine DEP, pg. 1, 3 – 5; North Carolina DAQ, pg. 36; Ohio EPA, pg. 6 – 7

NAAQS Implementation / Permit Grandfathering
See relevant comments from AAPCA members on:

- U.S. EPA's proposed Implementation Rule for the 2015 Ozone NAAQS: Arizona DEQ; Georgia EPD; Kentucky DEP; Ohio EPA; Nevada DEP; North Carolina DEQ; South Carolina DHEC; Texas CEQ; Virginia DEQ; Wyoming DEQ
- U.S. EPA's proposed 2015 Ozone NAAQS: Alabama DEM; Florida DEP; Georgia EPD; Indiana DEM; Kentucky DEP; Louisiana DEQ; Mississippi DEQ; Nevada DEP; North Carolina DAQ; North Dakota DAQ; Ohio EPA (Appendices A-F and G-I); South Carolina DHEC; Tennessee DAPC; Texas CEQ; Virginia DEQ; West Virginia DAQ; Wyoming AQD

4. **U.S. EPA update on Draft Title V Fee Guidance Documents (Feedback due September 20)**

- "Program and Fee Evaluation Strategy and Guidance for 40 CFR Part 70" (Title V Evaluation Guidance)
- "Updated Guidance on EPA Review of Fee Schedules for Operating Permit Programs under Title V" (Updated Fee Schedule Guidance)

5. **Other Questions and Comments**

6. **Adjourn**

*Background Information:

- Presidential Memorandum: Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing (January 24, 2017);
- In March 2017, the U.S. Department of Commerce issued a request for information, "Impact of Federal Regulations on Domestic Manufacturing.";
- Relevant Executive Orders: EO 13766: Expediting Environmental Reviews and Approvals For High Priority Infrastructure Projects (1/24/17); EO 13771: Reducing Regulation and Controlling Regulatory Costs (1/30/17); EO 13777: Enforcing the Regulatory Reform Agenda (2/24/17); EO 13783: Promoting Energy Independence and Economic Growth (3/28/17); and, EO 13807: Establishing Discipline and Accountability in the Environmental Review and Permitting Process for Infrastructure (8/15/17).

To: Beverly Parks[Parks.Beverly@epa.gov]
Subject: FW: SESARM presentation
SESARM 2017 Spring Deck w_TPs.pptx

Hi can you please print this out for me

-----Original Message-----
From: Wood, Anna
Sent: Thursday, June 01, 2017 9:53 AM
To: Banister, Beverly <Banister.Beverly@epa.gov>
Cc: Johnson, Yvonne W <johnson.yvonnew@epa.gov>
Subject: RE: SESARM presentation

Hi--I am looking for things to cut out as it is too long as I only have one hour--maybe Lynorae /Heather will take some of it and handle--attached is the draft. If it would be easier to touch base and talk through it to parse out I am available at noon to discuss. If I can remove some of the slides I'd actually like to include a slide on the EOs and SIP back log status from a national perspective which was not on the list Lynorae gave to Yvonne but I think would be good to cover -- let me know what you would like to do --I can meet with Lynorae and Heather if they are available at noon. Thx

-----Original Message-----
From: Banister, Beverly
Sent: Thursday, June 01, 2017 7:56 AM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: SESARM presentation

Good Morning Anna,
Have you completed your presentation for the SESARM meeting? We are trying to minimize duplication in presentations that will be given by Heather (permitting) and Lynorae (NAAQS implementation/SIPs etc).
If you are still working on it maybe we can have a quick chat related to the presentations. If you have completed it and can share with us that would be great.
Thanks,
Beverly
Sent from my iPhone

To: Wood, Anna[Wood.Anna@epa.gov]
From: David Friedman
Sent: Fri 11/3/2017 5:57:35 PM
Subject: RE: November 2 AFPM Meeting on NSR
Wehrum Weiss_NSR Reform in 2017 - Whats Next_ENV-2017-19.pdf

Anna- we appreciated your time as well as your staff's time yesterday. We thought it was a robust discussion and we look forward to future meetings on this topic. I have attached the paper that formed for the basis for Bill's presentation at our Environmental Conference in October.

From: Wood, Anna [mailto:Wood.Anna@epa.gov]
Sent: Friday, November 3, 2017 10:25 AM
To: David Friedman <DFriedman@afpm.org>
Subject: Re: November 2 AFPM Meeting on NSR

Hi David, thank you again for the conversation yesterday. It was very helpful to hear and better understand your members' perspective. Please send when you have a moment the presentation that Bill W used at your recent meeting as that would be very helpful and appreciated. Many thanks again and have a good weekend, Anna

Sent from my iPhone

On Oct 30, 2017, at 2:10 PM, David Friedman <DFriedman@afpm.org> wrote:

Anna- I am just confirming our meeting with you and your staff on Thursday, November 2 from 10-12. I have attached an agenda and the following folks will be in attendance:

Name	Company	State
David Friedman	AFPM	Virginia
Matthew Hodges	Valero Energy	Texas
Michael Hopperton	BP	Georgia
David Pavlich	Phillips 66	Oklahoma

Please let me know if you have any additional questions and we look forward to our meeting on Thursday.

David N. Friedman

Vice President

Regulatory Affairs

American

Fuel & Petrochemical

Manufacturers

1667 K Street NW

Suite 700

Washington, DC 20006

202.457.0480 office

202.602 6604 direct

202.457.0486 fax

dfriedman@afpm.org

<Agenda for AFPM-EPA Nov 2 Meeting.docx>

2017 Environmental Conference
Air Permitting/NSR/NAAQS Session
October 15-17, 2017
Grand Hyatt Denver
Denver, CO

ENV-2017-19 **NSR Reform in 2017 – What's Next?**

Presented By:

Kenneth Weiss, *ERM*
William Wehrum, *Hunton & Williams LLP*

NSR Reform in 2017 - What's Next:

Kenneth N. Weiss, P.E., BCEE, ERM

Introduction

Fifteen years after the last major effort to reform the New Source Review (NSR) program, the Trump administration is undertaking a major initiative aimed at regulatory reform. Not surprisingly, NSR is at the forefront as it remains as one of the most controversial regulatory program enforced by the U.S. Environmental Protection Agency (EPA). These rules historically have had substantial adverse impacts on the refining and petrochemical sector, in part due to lack of rule clarity and inconsistent rule application across the country and have been identified by AFPM as one of the five stationary source regulations of most concern to American Fuel & Petrochemical Manufacturers (AFPM) members[1]. This paper discusses regulatory changes that would be most beneficial to the refining and petrochemical sector and examines prospects to make such changes in the NSR program. The discussion is informed and enhanced by revisiting aspects of the 2002 NSR reform effort that ultimately were not successfully implemented and includes recommendations for a path forward.

Refining and Petrochemical Sector Challenges with NSR

The industry largely needs to concern itself with the impact of the NSR program on modifications to existing facilities as very few new facilities are being planned or constructed. Industry innovation has allowed the sector to meet demand by improving existing operations to accommodate needed demand. Yet the NSR regulations present challenges to refiners and petrochemical plants on two over-arching fronts:

1. The time required to obtain a permit widely varies across the United States for no real identifiable reasons and in many instances appears to extend for unreasonable periods of time. A search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) shows that the average time for final permit issuance of a new or modified source at a refinery since about 2005 is 14 months after submission of a complete application, with regional

[1] May 15, 2017 letter from David Friedman to Sarah Rees, EPA Office of Policy, and available at Docket ID Number EPA-HQ-OA-2017-0190

variability from 1 month to 7.5 years (RBLC search, 8/23/2017). There are thirty entries in the RBLC captured in the data search and 13 of them required at least a year to obtain a final permit.

This data is consistent with other industry wide studies. For example, Frass, Graham and Holmstead report that, "during the period from 2002 to 2014, the nationwide average time to obtain an NSR permit for coal- and natural gas-fired electric generating units (EGUs) and refineries was roughly14 months. This represents a substantial increase in average processing time for NSR permits compared with the reported permitting times for the 1997-2001 period. The distributions are skewed—median values are less than the mean—with some projects requiring substantially longer to obtain NSR approval. In addition, there was a significant variation across EPA regions in the processing time required for approval of new natural gas-fired EGUs— from seven months for Region 7 (Iowa, Kansas, Mississippi, and Nebraska) to 19 months for Region 9 (Arizona, California, and Nevada)."[2]

2. The actual implementation of the existing NSR rules is very complex and fraught with opportunities for error. A library of approximately 700 guidance documents sets out Agency interpretations and includes confusing and, at times, conflicting information. Moreover, the New Source Review Workshop Manual has not been updated since 1990 and, although, it is EPA's primary guidance document, it is chock-full of outdated information. It is this complexity that leads to the widely variable and inconsistent application of the regulations and that subjects the refining and petrochemical industry to needless and unwarranted potential enforcement exposure. This is not conjecture as NSR was one of the four marquis issues upon which EPA's refinery enforcement initiative was founded. The results of that effort since March 2000 are informative:

    a. Ninety-five percent of the nation's refining capacity have entered into settlement agreements with EPA in 37 settlement agreements;
    b. 112 refineries are impacted by these agreements;
    c. Settling companies have agreed to invest more than $7 billion in control technologies and payed civil penalties of more than $116 million.

In the NSR area much of the dispute between industry and the refining

2 EPA's New Source Review Pro gram: Time for Reform by Art Fraas, John D. Graham, and Jeff Holmstead, Environmental Law Institute 2017

sector hinged on different understanding and interpretations of the NSR rules. A more straight-forward program would be beneficial to all parties.

NSR Reform History and Related Actions

Practically, there are three mechanisms available to streamline the NSR rules and to provide clarity:

1. EPA can issue guidance memoranda and policy updates that have substantial impacts on the actual implementation of the rules either negatively or positively. Some policy documents add clarity to the process while others add administrative burden and complexity. These memoranda and guidance documents do not have equal standing to the actual regulations and are subject to judicial challenge but they often result in almost immediate changes to the rules. The downside to the policy approach is that policy can be changed by new policy. An example of this process is the "Wehrum Memo"[3] where the EPA, under the Bush administration, attempted to clarify the source definition for oil and gas fields. The then Acting Assistant Administrator for Air issued the Wehrum memo to clarify how EPA would address oil and gas fields. But when the Administration changed, the new Assistant Administrator reversed field[4] and walked back the Wehrum memo, which resulted in confusion that ultimately was resolved with a rulemaking (which, ironically, largely adopted the Wehrum memo approach).

   There are other policy and guidance issues that are nowhere near as well known as the Wehrum memorandum that can ease the burden associated with NSR permitting. A recent example is the revised Guideline on Air Quality Models[5] which contains several enhancements to guidance that can potentially offer relief to historically challenging and burdensome elements associated with PSD air quality modeling analyses. Among other enhancements, the revised guideline suggests that nearby sources to include in a PSD modeling analysis do not necessarily have to extend to over 50 km from the project site, which differs from the prescriptive approach described in the Draft 1990 New Source Review Workshop Manual. Additionally, the guidance now allows for consideration of actual emissions when doing a cumulative (multi-source) analysis, compared to

[3] Memorandum from William L. Wehrum, Acting Assistant Administrator, Office of Air and Radiation, to Regional Administrators I – X, Source Determinations for Oil and Gas Industries, January 12, 2007.
[4] Memorandum from Gina McCarthy, Assistant Administrator, Office of Air and Radiation, to Regional Administrators 1-X, Withdrawal of Source Determinations for Oil and Gas Industries
[5] 40 CFR 51 "Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter", Federal Resister/Vol. 82, No. 10/ January 17, 2017

previous guidance that required the use of potential-to-emit emissions for background sources which is a substantial and important improvement. The revised guideline also includes an option to utilize meteorological data derived from prognostic meteorological models in situations where representative meteorological data are not readily available. This should substantially reduce the need for in-the-field meteorological stations and already has streamlined the NSR process in some real examples.

2. EPA can promulgate changes to the existing NSR rules through a typical rulemaking process requiring the development of a proposed rule package, consideration of public comments and ultimately promulgation of revisions to the PSD rules. This is a time consuming process and requires substantial dedication of time and resources (as is the situation with any complex rule) and often leads to litigation.

   The last significant effort to accomplish a regulatory update of the NSR rules were the reforms promulgated in December 31, 2002. As discussed below, several of the changes EPA attempted to implement were successful while others ultimately were either abandoned or revoked. The industry should look to this history to better understand how to support successful updates to the NSR program that aim to address the lack of certainty and unpredictable permitting cycle time associated with the existing program. These issues are addressed in the next section of this paper.

3. Some changes to the NSR program can only be accomplished by amending the underlying Clean Air Act (CAA). Of course, any changes to the statute would require congressional action. For example, EPA does not have the authority to remove petroleum refineries from the list of 28 source categories subject to NSR when the potential to emit of a regulated pollutant equals at least 100 tpy as that requirement is part of the CAA. Only Congress can do this.

Changes that AFPM suggested in their comments to EPA about this subject potentially could be accomplished through any of these three categories. AFPM made the following recommendations to EPA with respect to the NSR Program:

1. Eliminate the need to consider emissions increases from non-modified affected emission units. This could be accomplished initially by policy and then by regulation. Note that EPA attempted this in the 2002 Reforms and this issue is addressed in a later section of the paper.

2. Allow project netting so that emissions reductions associated with a project can be considered in Step 1 of the PSD/NNSR applicability

analysis. This was once EPA policy and was an accepted approach. The 2006 proposed revisions to the NSR regulations included preamble language that appears to clearly allow project netting in some situations:

"Use of the phrase 'sum of the difference' between projected and baseline emissions indicates that one must look at the difference between the projection and the baseline. That difference may either be a positive number (representing a projected increase) or a negative number (representing a projected decrease). In either case, the values must be taken into consideration in determining the overall increase, or decrease, in emissions resulting from the project."[6]

Project netting should be restored for all purposes. This could most easily be accomplished by finalizing the still-pending 2006 proposal.

3. Use a "potential to potential" comparison of emissions to determine whether PSD/NNSR is triggered. Use of this test to trigger PSD would have to be squared with DC Circuit precedent holding that actual emissions must be used to determine whether a project results in a significant net emissions increase. At a minimum, regulatory language would be required as the existing rules do not accommodate this approach. This would likely be a contentious change to the regulations and would be litigated for certain.

4. Provide a definition of "project" to address uncertainty around project aggregation.

   EPA's existing policies addressing the "project" definition are confusing and adoption of a definition would certainly address this issue. It should be noted however that the Agency promulgated a Project Aggregation rule in January 2009[7] with no changes to the existing NSR rule text, so the preamble language provides EPA's most current interpretation or policy on aggregating projects. Under the subsequent Administration, EPA stayed the effectiveness of this rule and indicated that it planned to rescind the rule. This was never accomplished. Guidance published by EPA since staying the effectiveness of the rule leans on more restrictive prior guidance memoranda. There is nothing preventing EPA from removing the stay and allowing the 2009 rule to take effect although NRDC would object. This would provide some immediate certainty to the permitting process. The ENGO's still-pending challenge to the rule likely would go forward at that point.

[6] 71 FR 54235
[7] 74 FR 2376

The 2002 and 2003 NSR Reforms and Lessons Learned

In 1996, USEPA embarked upon a program to simplify the NSR program. The Agency proposed a series of changes to the PSD and non-attainment NSR rules that were intended to add clarity to the program applicability requirements. EPA also hoped to revise or eliminate program elements that created barriers to innovation, reliability, and efficiency without providing any real environmental benefit. These changes are commonly known as "NSR Reform."

Table 1 provides a snapshot of the current status of the NSR Reforms of most importance to the petroleum industry that USEPA attempted to finalize in 2002 and 2003 in summary form as well as some important later efforts.

Table 1 – NSR Reform Scorecard

	In Effect	Abandoned, Stayed or Revoked	Comment
10 yr. Baseline Emissions Look back	✔		
Actual to Future Actual Methodology	✔		
Actual Plantwide Applicability Limits (PALs)	✔		
Clean Unit Test		✔	
Pollution Control Project Exclusion		✔	
Flexible Permitting and NSR Green Groups		✔	
RMRR Bright-Line Test		✔	
Project Aggregation Rule		✔	
Source Aggregation Policy	✔		
Reasonable Possibility Rule	✔		
Fugitive Emissions Rule		✔	

There are many interesting history lessons to be learned from the 2002/2003 NSR Reform experience. Three of the most interesting issues that impact the refining and petrochemical sector include the:

- Actual to Future Actual Methodology (ATFA)

- Project Aggregation Rule
- Clean Unit/PCP Revocation

There are different lessons from each that should be remembered as efforts are aimed at updating the rule in the current years.

Use of the Actual to Future Actual Methodology

The use of the 10-year baseline and actual to future actual methodology (ATFA) to determine emissions increases can be enormously beneficial. Proper application of these elements of the NSR program allows the regulatory agency and the emissions source to focus time on those projects that result in real increases in air pollution. However, time has shown that what should be a relatively straight-forward determination is not in fact so straight-forward.

There is a long running dispute between EPA and DTE Energy Company that is informative. The issue at the center of the DTE controversy involves the proper application of the ATFA method of determining emissions increases promulgated as part of the 2002 NSR reform rules. This is the first case addressing the revised applicability provisions of the reform rules.

The facts of the case are relatively straight-forward. DTE undertook a project at the Monroe Station in 2010 to replace various boiler tube components. As required, the company provided notice to the Michigan permitting authority of the planned projects along with emissions projections that showed no significant emissions increase or applicability of the NSR rules. The permitting authority did not question the emissions projections.

In 2010, the Department of Justice filed a complaint against Detroit Edison alleging violations of Michigan's NSR rules related to certain maintenance projects. Essentially, EPA did not agree with DTE's emissions projections and even though post change actual emissions have, in-fact, been lower than baseline emissions, EPA's position has been that it nevertheless may second-guess the company's projection. The enforcement action against Detroit Edison's Monroe station is the first post NSR Reform dispute on this topic.

DTE in the protracted litigation claimed that actual emissions after the upgrades showed NSR should not have been triggered and that EPA does not have authority under the 2002 rules to second guess DTE's projection. The district court agreed. The 6th Circuit in the first appeal of the suit in 2013, known as DTE1, reversed the district court, but only on the narrow grounds that EPA should be able to challenge a pre-project emissions projection that does not facially conform to the rule. On remand, the U.S. District Court for the Eastern

District of Michigan again found in favor of DTE, finding no facial flaw in DTE's projections -- only to be reversed again in the Jan. 10 ruling known as DTE2. This is a fractured decision that overturned the district court, but provided no clarity on the law because the three judges issues three separate, and disparate, opinions. DTE is currently seeking review of DTE2.

The lesson here is that even though a regulatory change is indeed promulgated as the ATPA reforms were promulgated in 2002, explicit regulatory language or detailed preamble guidance is necessary to ensure proper interpretation of the rule language.

Project Aggregation Rule

As noted previously, EPA addressed the Project Aggregation issue in a 2006 proposed rule and a 2009 final rulemaking[8]. Under this rule, sources and permitting authorities should combine emissions only when nominally separate changes are "substantially related." Further, two nominally-separate changes are not substantially related if they are only related to the extent that they both support the plant's overall basic purpose. This rule adopted a rebuttable presumption that nominally-separate changes at a source that occur three or more years apart are presumed to not be substantially related. EPA has stayed the effective date of that final rule due to a petition for reconsideration and EPA continues to follow its historic approach to aggregation.[9]

Removing the stay would resolve many of the issues refiners face and could provide the improved certainty that would benefit refiners. This may be a path to avoid a new rulemaking process. The new Administration would need to resolve the NRDC petition for reconsideration and pending judicial challenge in this event.

Clean Unit Test/Pollution Control Project Exclusion Revocation

The 2002/2003 NSR Reform rules included the introduction of a new "Clean Unit" Test exempting certain emissions units that meet emission limitations by installing stringent air pollution controls from NSR, and an expansion upon the pollution control project NSR exemption initially promulgated on July 21, 1992 (57 FR 32314). The United States Court of Appeals for the District of Columbia vacated both the Clean Unit Test and pollution control project exemption in an opinion issued on June 24, 2005. The court's basis for vacating these two

---

[8] 71 Fed. Reg. 54235 (Sept. 14, 2006) (proposed rule); 74 Fed. Reg. 2376 (Jan. 15, 2009) (final rule).
[9] 72 Fed. Reg. 19567 (April 5, 2010).

exemptions from the NSR program is that actual emissions must be used in determining whether a project results in a significant net emissions increase.

This decision should inform the viability of certain changes to the NSR rules. Notably suggested updates to the rules that could be viewed to allow increases in actual emissions without requiring preconstruction review may require amendments to the underlying Clean Air Act. Some parties, for example, might argue that a potential to potential emissions test to determine NSR applicability would result in allowing increases in actual emissions and, thus, such an applicability test might run counter to DC Circuit precedent.

Other Rule Changes Being Suggested to EPA

EPA's regulatory reform docket (No. EPA-HQ-OA-2017-0190) currently contains approximately 63,500 comments providing input to EPA on the topic of regulatory reform. Suggestions to improve the NSR permitting program are prominently featured in the docket along with some very damning comments such as:

- New Source Review (NSR) is the CAA's most broken program
- "NSR imposes the most burden on NEDA/CAPs members speaking about all EPA regulations"
- "As a group, the multiple conservative and burdensome set of air quality regulations surrounding NSR permitting are a deterrent to manufacturing facility modifications and expansions"
- The American Fuel & Petrochemical Manufacturers (AFPM) said that NSR reform was the one change they would make, if it could, to the federal permitting process
- "The NSR program has become a significant impediment to the construction and expansion of manufacturing facilities in the United States"

These comments fall in broad categories and included many recommendations to improve the NSR permitting program. Most of the comments can be parsed into one of four categories:

1. Changes that will streamline the permitting process and certainty
2. Changes to the applicability determination
3. Changes to the BACT determination
4. Changes to Ambient Impact Analysis

Based on the lessons learned from the 2002/2003 reform efforts, it is possible to understand which of the recommendations can be accomplished by policy and could occur in the relatively short-term future, which require regulatory updates and thus are probably five or more years off before being implemented, and which might require amendments to the Clean Air Act, which are unpredictable but will also include follow-on regulations and thus have the longest time frame to implementation.

Recommendations Regarding Streamlining and Certainty

- Redefine State vs. EPA Role defaulting to state leadership and avoiding EPA second-guessing -*This can be accomplished by policy and is consistent with the current Administration's approach*

- Rethink "Begin Actual Construction" allowing some construction at risk - *It should be possible to accomplish this by policy. Some State SIP approved NSR programs actually use this approach*

- Reduce the need to rely upon a library of more than 700 guidance documents –*Reliance on guidance can be reduced, but there will still be a need and a role for guidance.*

- Update guidance documents and put into an easy to understand form – *This should happen. There is no reason that the guidance library is not better maintained.*

- Update and codify the 1990 draft New Source Review Workshop Manual – *The Manual should be updated. The Air & Waste Management Association, in fact, has just released an update to fill the vacuum created by EPA. It is disappointing that such an important guidance manual has not been updated in 27 years. Codifying the Manual would require rulemaking and is not likely to occur in the near term.*

- Add rigor to the "completeness determination" – *This can be accomplished by policy*

- Define RMMR – e.g. as a percentage of new unit cost – *The author agrees that the RMMR definition needs improvement. Use of this metric, i.e. percentage of new unit cost did not survive the prior effort to streamline the NSR rules. Some people view such an approach as inconsistent with the CAA and thus this approach might require revisions to the CAA. This is not to say that the existing definition of RMRR could not be updated by policy.*

Recommendations Regarding Applicability

- Use the NSPS hourly emissions applicability test for the NSR trigger or use the hourly emissions to trigger the significant emissions increase test – *this approach is very similar to a potential to potential emissions test and faces the challenges previously discussed. It may require an update to the CAA.*

- Provide a definition of "project" to address uncertainty around project aggregation – *See the prior discussion. A rule is ready to be implemented*

- Reinstate the Pollution Control Policy – *see the prior discussion but this would appear to require an update to the CAA.*

- Eliminate the need to consider emissions increases from non-modified affected emission units – *this is an approach to resolving the debottlenecking challenge and could potentially be resolved through policy or rulemaking.*

- Allow Project Netting – *see prior discussion. This was the policy once and could easily be implemented by finalizing the pending proposal.*

- Develop source-specific major modification definitions for the 28 source categories akin to Permits by Rule – *this would require rule revisions and thus is a longer term change*

BACT/LAER Recommendations

- Rethink BACT Process: Top-Down is 30 years old – *The BACT Process is policy so this can be accomplished as a policy update or by rule.*

- Expand the economic analysis to include job losses and other costs – *This is a policy decision*

- Reconsider Clean Unit Exemption – *See prior discussion as this might require an amendment to the CAA*

- Rethink SERs – *for example, GHGs might be 250,000 tpy – this would require rulemaking. EPA's pending proposal for GHGs could be finalized relatively quickly. For other pollutants, it is not a short-term effort.*

- Make clear that CCS is not BACT for refineries – *EPA could issue a policy document on this topic.*

- Use NSPS and MACT as presumptive BACT – *This might require an update to the CAA as BACT is a defined CAA term.*

- Submit the Top-Down BACT process to review and comment – *In essence this means codifying the Top-Down BACT process and would require rulemaking. Although this could be accomplished over time the benefits might be elusive.*

- Issue consistent cost guidance - *This does not require rulemaking by definition*

- Rethink LAER using Offsets as a backstop – *this might require changes to the CAA as LAER is a defined term in the Act.*

Ambient Impact Analysis and Related Issues Including Emissions Offsets

- Addressing Dispersion Model Conservatism & Worst-Cast assumptions – *Policy can be used to address such issues as emissions variability, meteorology variability, and background concentration variability among other issues.*

- Address the use of Ambient Monitoring vs Dispersion Modeling results where current policy defaults to model results – *policy updates can make a significant difference.*

- Rethink role of EPA and Model Clearinghouse – *a collaborative state approach could resolve bottlenecks created by the Model Clearinghouse.*

- Availability (or Unavailability) of Emissions Offsets especially in Areas of the Country where Emissions Offsets are Constrained such as the Northeast, California and Rural communities that have no significant industry but are Ozone or $PM_{2.5}$ Non-attainment areas – *regulatory changes could be used to secure some relief. These include expanding areas where offsets may originate, expanding the contemporaneous time period, and lifting certain restrictions on generating offsets at minor sources.*

Conclusions

There are many opportunities to improve the NSR permitting program. The lowest hanging fruit are those changes and improvements that can be accomplished by policy or regulations that are ready now to be promulgated. For the refining sector, many of the most important suggested improvements can be accomplished by such updates including better definition of the Project, use of Project netting and the need to consider emissions increases from units that are unchanged. Some changes, however, require rule revision or statute revision. These are not likely to occur in the short-term and should be addressed as part of a longer term look at regulatory reform. Regulatory changes do happen. The 2002 Reforms prove the benefit of updating the regulation but the time to make such changes is measured in more than a few years or a decade. The best approach is to understand which updates can be accomplished by policy and which deserve more attention through a more intensive effort.

To: Banister, Beverly[Banister.Beverly@epa.gov]
Cc: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Tue 10/10/2017 6:51:34 PM
Subject: 2017 Fall Full Deck w_TPs
2017 Fall Full Deck w_TPs_oct 10.pptx

As requested by Anna, I am forwarding to you our latest "full deck" of slides along with talking points. Please let me know if you have any questions or need additional information.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Tue 9/19/2017 8:02:49 PM
Subject: latest version of full deck
NACAA 2017 Fall Full Deck w_TPs_sept 19.pptx

Hard copy in your chair.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Tue 4/25/2017 2:11:32 PM
Subject: here are the files and the agenda
Spring2017Agendadraftversion040517.pdf
WESTAR NAAQS Implementation Update_FINAL.TPs.pptx
WESTAR Ozone_Implementation Update_FINAL_TPs.pptx
WESTAR RH Rule _FINAL_TPs.pptx

Thank you,

Yvonne W. Johnson
Special Assistant to the Director
Air Quality Policy Division
Office of Air Quality Planning & Standards
U.S. Environmental Protection Agency
919-541-3921
johnson.yvonnew@epa.gov

-----Original Message-----
From: Wood, Anna
Sent: Tuesday, April 25, 2017 10:03 AM
To: Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>
Subject: Can you please send me

All the slide decks for Westar with talking points. They cancelled my flight and rebooked me on a 100 pm flight to Charlotte then to San Diego arriving around 900 pm PST.

I'm a little worried about my luggage arriving with me and unfortunately, my meeting note book is in my luggage so I just want a back up in case I need it- I'm almost tempted to punt on the travel - but hopefully the rest of the flights will go ok :-)

Sent from my iPhone

~ Draft Agenda 4/5/2017 ~

WESTAR and WRAP Spring Business Meeting

April 26-27, 2017
San Diego, CA
Call-in number: 1-800-768-2983 code 3545016
All agenda times are Pacific Daylight Time

Wednesday, April 26

7:30 - 9:00 am WESTAR WRAP breakfast (Del Mar Patio)

8:30 – 9:45 am WESTAR Council Executive Session (Bahia Belle Room), Tribal Caucus (Room 612) meetings.

10:00 am Opening of WESTAR - WRAP meeting (Del Mar Room)

- WRAP Board welcome – Randy Ashley, Confederated Salish, Pend d' Oreilles, and Kootenai Tribes, Tribal Co-Chair and Gordon Pierce, State Co-Chair
- WESTAR Council welcome – Terry O'Clair, ND, President
- Introductions around the room and on the phone
- CARB introduction to CA presentation (Kurt Karperos, CA)

Business and Organizational Activities

- Staff reports (Tom Moore, Bob Lebens, Jeff Gabler, WESTAR-WRAP)
- Committee reports (Jay Baker, Planning Committee; Stephen Coe, Technical Committee; Gordon Pierce, National Monitoring Committee; Patrick Barickman, Technical Steering Committee)
- Upcoming Meetings and Events
- Financial report (Mary Uhl, WESTAR-WRAP)

11:45 am Lunch on your own

1:00 pm OAQPS update (Anna Wood, OAQPS)

2:15 pm Future Air Quality Management in the West

- CARB
- Current and future western EGU emissions trends (Patrick Cummins, CNEE)

3:15 pm Break (Del Mar Patio)

3:30 pm Future Air Quality Management in the West (continued)

- Washington Ecology (Nancy Pritchett, WA)
- Environmental perspective —Tim O'Connor, EDF
- Industry perspective —Reuben Plantico, WEST Associates
-

5:00 pm Adjourn for the day

5:45-7:45pm No Host dinner – WaveHouse Cabanas – 3215 Ocean Front Walk (5 min walk from hotel)

Thursday, April 27

7:00 – 8:00 am WESTAR WRAP breakfast (Del Mar Patio)

8:00 am Roundtable – Protocols and Innovations in VW settlement fund use

9:00 am Mgmt. of Regional Analysis efforts for planning through Interagency coordination
- CARB (Tina Suarez-Murias, CA)
- NW Airquest (Rick Hardy, ID)
- IWDW (John Vimont, NPS)

9:45 am Break

10:00 am Regional Coordination – Visibility Analysis/Planning
- RHR summary (Phil Lorang, EPA)
- WESTAR/WRAP Regional Haze workplans (Jay Baker, UT)
- Technical Analysis (Patrick Barickman, WRAP Technical Steering Comm. Chair)

11:15 am Smoke Management / Fire Impact Response Programs: CARB initiatives & communication (Dar Mims, CA)

11:45 am Lunch provided (Del Mar Patio)

1:00 pm Ozone analysis and planning
- background ozone workshop outcomes (Tom Moore)
- good neighbor transport SIPs and implementation of 2015 standard (Anna Wood, OAQPS)
- Utah Ozone Advance experience and wintertime ozone formation (Brock LeBaron, UT)

2:00 pm WESTAR-WRAP Governance workgroup report-out

3:00 pm Break (Del Mar Patio)

3:15 pm Particulate Matter
- Advance examples
  - MT (Stephen Coe, MT)
  - OR (David Collier, OR)
- SIP bump up (Bryce Bird, UT)

4:15 pm Hot Topics: woodstove changeout programs and NSPS (Bob Lebens)

5:00 pm Adjourn

NAAQS AND OTHER IMPLEMENTATION UPDATES

Anna Marie Wood, Director
Air Quality Policy Division
OAQPS, U.S. EPA
WESTAR Spring Meeting
2017

OVERVIEW

- NAAQS Implementation Updates
  - Sulfur Dioxide (SO_2)
  - Fine Particulate Matter ($PM_{2.5}$)
- Exceptional Events
- Startup, Shutdown, and Malfunction (SSM) Policy for SIPs and SIP Call
- NSR and Title V Permitting Updates
- Reducing the SIP Backlog
- State Plan Electronic Collections System for SIPs

NAAQS Reviews: Status Update

(April 2017)

	Ozone	Lead	Primary NO_2	Primary SO_2	Secondary (Ecological) NO_2, SO_2, PM[1]	PM[2]	CO
Last Review Completed (final rule signed)	Oct. 2015	Sept 2016	Jan 2010	Jun 2010	Mar 2012	Dec 2012	Aug 2011
Recent or Upcoming Major Milestone(s) [3]	TBD[4]	TBD[4]	Jan 2016 Final ISA Sep 2016 1st Draft PA Spring 2017 Final PA	Dec 2016 2nd Draft ISA Feb 2017 REA Planning Document March 2017 CASAC review of Draft ISA and REA Planning Document	Jan 2017 Final IRP Spring 2017 CASAC review of 1st Draft ISA	Dec 2016 Final IRP Winter 2017/2018 1st draft ISA REA Planning Document	TBD[4]

Additional information regarding current and previous NAAQS reviews is available at:
http://www.epa.gov/ttn/naaqs/

[1] Combined secondary (ecological effects only) review of NO_2, SO_2, and PM
[2] Combined primary and secondary (non-ecological effects) review of PM
[3] IRP – Integrated Review Plan; ISA – Integrated Science Assessment; REA – Risk and Exposure Assessment; PA – Policy Assessment
[4] TBD = to be determined

Anticipated NAAQS Implementation Milestones

(April 2017)

Pollutant	Final NAAQS Date	Designations Effective	Infrastructure SIP Due	Attainment Plans Due	Attainment Date
$PM_{2.5}$ (2006)	Oct 2006	Dec 2009	Oct 2009	Dec 2014	Dec 2015 (Mod) Dec 2019 (Ser)
Pb (2008)	Oct 2008	Dec 2010-2011	Oct 2011	June 2012-2013	Dec 2015-2019
$PM_{2.5}$ (2012)	Dec 2012	Apr 2015	Dec 2015	Oct 2016 (Mod)	Dec 2021 (Mod) Dec 2025 (Ser)
NO_2 (2010) (primary)	Jan 2010	Feb 2012	Jan 2013	N/A	N/A
SO_2 (2010) (primary)	June 2010	Oct 2013, Sept 2016 (+2 rounds)	June 2013	April 2015, March 2018 (2019, 2022)	Oct 2018, Sept 2021 (2023, 2026)
Ozone (2008)	Mar 2008	July 2012	Mar 2011	Mid 2015-2016	Mid 2015-2032
Ozone (2015)	Oct 2015	Dec 2017	Oct 2018	Dec 2020-2021	2020-2037

2010 SO_2 NAAQS Implementation

- EPA revised **Primary NAAQS for Sulfur Dioxide (SO_2) standard** on June 3, 2010 to 75 ppb/1-hour (75 FR 35520)

- EPA designated 29 areas as nonattainment on July 25, 2013 (Round 1)
  - **Guidance for 1-hr SO_2 NAAQS NAA SIP Submissions** was issued on April 23, 2014
  - Attainment plans for the 29 areas were due April 4, 2015
  - EPA issued findings of failure (FFS) to submit attainment plans for 16 areas in 11 states, effective April 18, 2016 (81 FR 14736; published March 18, 2016)

- EPA is required to promulgate a Federal Implementation Plan (FIP) if a state does not submit, and EPA does not approve the required SIPs within 24 months of the effective date of the FFS (i.e., April 18, 2018)

- EPA is working with affected states to develop SIPs

2010 SO_2 NAAQS Designations

- Consent decree entered on March 2, 2015, by U.S. District Court for Northern California in *SIERRA CLUB and NATURAL RESOURCES DEFENSE COUNCIL v. EPA* "triggered" the following deadlines:
  - July 2, 2016 - The EPA must complete a round of designations for 61 areas associated with approximately 64 EGUs in 24 states and any undesignated areas with violating monitors ("Round 2" designations)
  - December 31, 2017 - The EPA must complete an additional round of designations for any area a state has not established a new monitoring network by January 1, 2017 per the provisions of the SO_2 Data Requirements Rule
  - December 31, 2020 - The EPA must complete designations of all remaining, undesignated areas (expected to be areas where states elected to monitor per the provisions of the DRR)

2010 SO_2 Designations Due on July 2, 2016 Under Consent Decree

- On June 30, 2016, EPA finalized designations for 61 areas for "Round 2":
  - Areas where there are sources (electric power plants) that as of March 2, 2015, have not been "announced for retirement," and
  - Areas that meet one of the following emissions thresholds:
    - 16,000 tons of emitted in 2012 or
    - 2,600 tons of SO_2 emitted in 2012 with an average emission rate of at least 0.45 pounds of SO_2 per mmBtu
  - Areas where 2013-15 data indicate monitored violations – only Hawaii County, HI – which was determined to be an Exceptional Event

- These designations included 4 nonattainment areas, 41 unclassifiable/attainment areas, and 16 unclassifiable areas

SO_2 NAAQS Data Requirements Rule: Milestones

- **January 15, 2016:** Deadline for air agency to identify applicable sources (i.e., those exceeding threshold and other sources for which air quality will be characterized)
  - EPA notified states in March 2016 that review of source lists was complete. In a few cases, EPA added sources to characterization list
- **July 1, 2016:** Deadline for air agency to specify (for each applicable source) whether it will monitor air quality, model air quality, or establish an enforceable limit
  - Air agency also accordingly submits a revised monitoring plan, modeling protocols, or descriptions of planned limits on source emissions to less than 2,000 tpy, or documentation that a source has shut down
- **January 2017**
  - January 1: Deadline for new monitoring sites to be operational
  - January 13: Deadline for air agency to submit modeling analyses or documentation of emission limits/shut down
- **Early 2020:** Monitoring sites will have 3 years of quality-assured data which must be submitted to EPA

- EPA's website has recently been updated with state submittals associated with these milestones and related correspondence with EPA
  - https://www.epa.gov/so2-pollution/final-data-requirements-rule-2010-1-hour-sulfur-dioxide-so2-primary-national-ambient

Intended Schedule for Area Designations for 2010 SO_2 NAAQS Due on December 31, 2017 (Round 3)

Milestone	Date
States and tribes may submit updated recommendations and supporting information for area designations to the EPA	No later than January 13, 2017
States and tribes submit modeling analyses pursuant to SO2 Data Requirements Rule	No later than January 13, 2017
States submit exceptional events demonstrations for event-influenced SO2 monitoring data from 2015-2016	No later than July 14 , 2017
The EPA notifies states and tribes concerning any intended modifications to their recommendations (120-day letters)	on/about August 14, 2017 (no later than 120 days prior to final designations)
The EPA publishes public notice of state and tribal recommendations and the EPA's intended modifications and initiates 30-day public comment period	on/about August 24, 2017
End of 30-day public comment period	on/about September 24, 2017
States and tribes submit additional information, if desired, to demonstrate why an EPA modification is inappropriate	No later than October 13, 2017
The EPA signs notice promulgating final SO2 area designations for Round 3	on/about December 14, 2017 (can be no later than December 31, 2017)

$PM_{2.5}$ NAAQS Implementation: SIP Requirements Rule

- **$PM_{2.5}$ NAAQS SIP Requirements Rule** finalized on August 24, 2016 (81 FR 58010) provided framework for planning requirements for 2012 and future $PM_{2.5}$ NAAQS and informs implementation for areas still violating 1997 and/or 2006 $PM_{2.5}$ NAAQS

- November 2016 EPA issued draft **$PM_{2.5}$ Precursor Demonstration Guidance**
  - Recommends technical approaches for precursor demonstrations to assess whether air quality impact from a particular precursor can be considered to be insignificant in a given area
  - Comment period extended to March 31, 2017

- South Coast Air Quality Management District filed suit challenging two aspects of the rule:
  1. Requirement that emissions reductions for RFP come from sources within the nonattainment area (consistent with past court decision)
  2. Lack of explicit "de minimis" source category exclusion for Reasonably Available Control Measures (RACM) and Best Available Control Measures (BACM)
  - Petitioner's brief due on April 4, 2017; EPA response brief due June 6, 2017

2006 $PM_{2.5}$ NAAQS Implementation

- In December 2016, EPA proposed:
  - Determinations of attainment for 7 areas
  - Findings of failure to attain by the December 31, 2015 attainment date, and reclassification to Serious for 4 areas
  - The action is a mandatory requirement under the CAA and will fulfill obligations included in consent decrees resulting from two lawsuits.

- Serious area attainment date is December 31, 2019
  - Extension up to December 31, 2024 is possible if cannot demonstrate attainment by 2019. Requires Most Stringent Measures in any state.

- EPA plans to take final action this year on a number of submitted Moderate area plans and will continue to work with states developing Serious area plans to address air quality challenges.

2012 $PM_{2.5}$ NAAQS Implementation

- December 14, 2012 revised the $PM_{2.5}$ NAAQS primary annual $PM_{2.5}$ standard to 12µg/m^3 (78 FR 3086)
  - Nine Moderate nonattainment areas were designated in 2015
  - Moderate area attainment plan due date - October 2016
  - Moderate area attainment date - December 31, 2021
  - Serious area attainment date - December 31, 2025

Progress on $PM_{2.5}$ NAAQS Attainment

(as of April 2017)

	1997 $PM_{2.5}$ (2005 Designations)	2006 $PM_{2.5}$ (2009 Designations)	2012 $PM_{2.5}$ (2015 Designations)
Initial Nonattainment Areas	39	32	9
Areas Redesignated to Attainment	31	16	0
Current Nonattainment Areas	8	16	9
Clean Data Determinations	5	8	1
Proposed Redesignations	0	0	0

Exceptional Events

- On September 16, 2016, the EPA finalized the **2016 Revisions to the Exceptional Events Rule**, which address issues raised by stakeholders and increase the administrative efficiency of the Exceptional Event demonstrations process
  - https://www.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
  - Rule effective date 9/30/16; Published in Federal Register on October 3, 2016 (81 FR 68216)
  - NRDC/Sierra Club filed a Petition for Review on December 2, 2016

- General Exceptional Events Rule Background
  - Establishes procedures and criteria for identifying and evaluating air quality monitoring data affected by exceptional events
  - Provides a mechanism by which air quality data can be excluded from regulatory decisions and actions
  - Applies to all criteria pollutants and NAAQS and all event types to which the rule applies
  - Applies to all state air agencies, to (delegated) local air agencies, to tribal air agencies that operate air quality monitors that produce regulatory data and to federal land managers/federal agencies if agreed by the state
  - Affects design value calculations, NAAQS designation decisions, attainment determinations, and State / Tribal / Federal Implementation Plan (SIP/FIP/TIP) development

- Final Wildfire/Ozone Exceptional Events Implementation Guidance

Exceptional Events Implementation: Stakeholder Feedback

- November 2016 implementation workshops for states and tribes (Denver – 11/8/16; Dallas – 11/30/16)
- General feedback
  - Participants were generally pleased with both the rule revisions and the content of the workshop
  - Participants requested further guidance and similar implementation workshops (both for exceptional events and other EPA programs) and asked for follow-up communication and outreach workshops/webinars following promulgation
  - Participants asked that EPA continue to find ways to reduce the transaction costs in exceptional events demonstrations
  - Participants called for continued EPA communication and support with more tools and examples as they become available

Exceptional Events Implementation: Available Resources

- Exceptional Events Website at http://www2.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
- Quick reference guide for exceptional events demonstrations
- Examples of reviewed exceptional event submissions
- Best practices documents
- Links to publicly available support information and tools
- Links to rule and guidance resources
  - Final rule
  - Final wildfire/ozone guidance
  - Fact sheets
  - 2013 interim guidance documents

Exceptional Events Implementation: Next Steps

- The 2016 rule revisions and final wildfire/ozone guidance were needed first steps, but efficient and coordinated implementation is critical.
- What is next?
- Additional Implementation Materials
  - Revisions to 2013 *Interim Exceptional Events Guidance Documents*
  - Stratospheric Ozone Intrusion Document
  - Alternate Paths for Data Exclusion Document
  - Prescribed Fire/Ozone Document
- Continued development of exceptional events tools
  - Templates
  - Website updates
  - AQS modifications to reflect rule revisions guided by feedback from newly created AQS workgroup
  - Standardized metrics and tracking
  - Targeted efforts with FLMs – communications and tools
  - Best practices for multi-state exceptional events demonstrations

Response to SSM Petition, Final Policy and SIP Call

- Final action was signed May 22, 2015, in response to a Sierra Club petition for rulemaking concerning SIP provisions for treatment of excess emissions occurring during periods of startup, shutdown and malfunction (SSM)
  - Final notice restates EPA's SSM Policy as it applies to SIPs with one change regarding affirmative defense (AD) provisions
- SIP Call applies to 36 states (45 jurisdictions), the majority of which were named in the original petition
- Challenge from multiple parties pending in D.C. Circuit Court

Draft Guidance on Significant Impact Levels (SILs) for Ozone and $PM_{2.5}$ in the Prevention of Significant Deterioration Permitting Program

- Draft guidance was posted August 18, 2016 and had a 60 day comment period through September 30, 2016
  - Draft guidance includes a memorandum that identifies recommended SIL values for ozone and $PM_{2.5}$ and describes how these values may be used in a PSD compliance demonstration;
  - A technical basis document (with supporting appendices) describing how EPA developed the SIL values for $PM_{2.5}$ and ozone; and
  - A legal support document that discusses a legal basis that permitting authorities may choose to apply if allowing sources to use SILs as part of their compliance demonstrations.
  - https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant
- Timing: TBD

Title V Permitting

- Title V Program and Fee Evaluation Guidance
  - Satisfies EPA commitments in response to a 2014 Office of Inspector General (OIG) report recommending enhanced oversight of state and local title V program fee revenue practices
    - Committed to completing the revised guidance by Fall 2017
  - Provides guidance for EPA regions on conducting state and local title V program and fee evaluations
  - Discretionary for EPA regions and no specific requirements for state programs
  - Consistent with the principles and best practices for oversight of state permitting programs contained in the August 30, 2016 document *"Principles and Best Practices for Oversight of State Permitting Programs"*, developed by EPA's Cross-Media State Programs Health and Integrity Workgroup

- Timing: TBD

Revisions to the Petition Provisions of the Title V Permitting Program

- Proposed rulemaking to increase transparency and stakeholder understanding of the petition process, as well as ensure that the Agency is able to efficiently address related programmatic and air quality issues was published on August 24, 2016 (81 FR 57822)

- The proposed revisions:
  - provide direction for submitting title V petitions, including encouraging the use of an electronic submittal system;
  - require mandatory content and format for title V petitions; and
  - require permitting authorities to respond in writing to significant comments received during the public comment period on draft title V permits.

- The preamble also provides guidance on “recommended practices” for permitting authorities and sources to help ensure title V permits have complete administrative records and are consistent with the CAA
  - If followed, these practices may reduce the likelihood that a petition will be submitted on a title V permit

- The comment period closed on October 24, 2016 and EPA is in the process of reviewing the comments received. Timing: TBD

Regulatory Updates for GHG Permitting

- EPA has taken a series of steps to respond to the June 23, 2014, Supreme Court decision in *Utility Air Regulatory Group (UARG) v. EPA* and the April 10, 2015, Court of Appeals for the District of Columbia (D.C. Circuit) *Coalition for Responsible Regulation v. EPA Amended Judgment*
  - In April 2015, EPA issued a final rulemaking revising EPA's PSD regulations to enable the EPA to rescind EPA-issued PSD permits for GHG
    - Direct Final (80 FR 26183); Parallel Proposal (80 FR 26210)
  - In August 2015, EPA issued a final **Prevention of Significant Deterioration and Title V Permitting for Greenhouse Gases: Removal of Certain Vacated Elements Rulemaking** (80 FR 50199)
    - Rule removed certain provisions from PSD and title V that were vacated as part of the D.C. Circuit Court's April 2015 Amended Judgment
  - On August 26, 2016, EPA proposed the **Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program** (81 FR 68110)
    - Rule also proposed the remaining changes to PSD and title V that are necessary to fully implement the D.C. Circuit Court's April 2015 amended judgment
    - The public comment period closed on December 16, 2016 and EPA is currently reviewing comments. Timing: TBD

Removal of Emergency Provisions from Part 70 and 71

- Proposed **Removal of Title V Emergency Affirmative Defense Provisions From State Operating Permit Programs and Federal Operating Permit Program Rule** to remove the "emergency" affirmative defense (AD) provisions from title V regulations 40 CFR 70.6(g) and 71.6(g) published on June 14m 2016 (81 FR 38645)

- The public comment period closed on August 15, 2016, and the EPA is currently evaluating all comments received

- This is a follow-up action to similar rulemakings, including the 2015 SSM SIP Call, intended to ensure that the EPA's policy on AD is consistent across all CAA program areas, following the D.C. Circuit's *2014 NRDC v. EPA* decision

- Timing: TBD

SIP Processing Improvements

- NACAA-ECOS-EPA SIP Reform Workgroup discussed need to reduce the SIP backlog and improve SIP processing

- Successful Implementation of Key Principles:
  - Set a goal of clearing the current backlog (as of October 1, 2013) by the end of 2017
  - Manage the review of all other SIPs consistent with Clean Air Act deadlines
  - Develop 4-year management plans agreed upon by EPA Regions and states that identify the highest priority SIPs to process and meet the backlog reduction goal
  - Use best practices and tools developed through the $PM_{2.5}$ Full Cycle Analysis Project (FCAP) to facilitate SIP processing
  - Increase transparency of SIP review status and improve EPA's SIP tracking system with fields that could be of assistance to states

SIP Processing Improvements (Con't)

- Trends in SIP Processing
  - EPA and air agencies are implementing the best practices from the $PM_{2.5}$ Full Cycle Analysis to improve SIP processing and assessing effectiveness to ensure continued improvement
  - 4-year management plans in place for each state
    - Will continue to coordinate with states on multi-year SIP management plans as a standard practice
  - EPA and states making good progress on eliminating the SIPs backlogged as of October 1, 2013
    - Backlogged SIPs reduced by 70%
  - EPA and states working together to prioritize SIPs and manage the review of all other SIPs consistent with Clean Air Act deadlines
    - Active SIPs reduced by 32%

SIP Processing Improvements: Integrated Electronic System for SIP Submissions

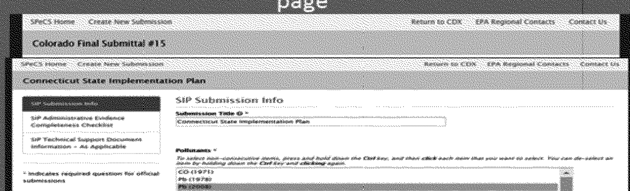
- Our vision is to create an integrated electronic submission system for SIPs and other state plans that enables us to:
  - Manage state submissions more efficiently and effectively
  - Increase transparency through data availability

- EPA embarking on project to leverage new Agency IT systems to improve and modernize the SIP submission process by allowing for:
  1) Developing and transmitting SIP submissions;
  2) Internal EPA review, collaboration, tracking and storage of plans;
  3) External public interface that provides status information on EPA action on SIPs, links to submittals, and links to FR notices; and
  4) Additional functionality, such as maintaining SIP compilations and accommodating other types

Vision: SPeCS for SIPs: Major Components

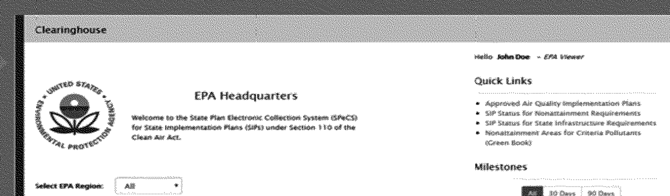
State Plan Collection Interface

Compilation and submission of plans using checklists, file upload capability, completeness checks and a state landing page



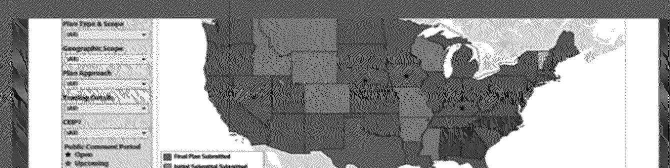
EPA Plan Review Clearinghouse

SIP requirement tracking, Issue tracking, storage of submittals and compliance with SIP requirements



Public Dashboard

Plan status updates, links to final approved plans, national and individual state SIP information



Questions and Comments

To: Wood, Anna[Wood.Anna@epa.gov]
Cc: Kornylak, Vera S.[Kornylak.Vera@epa.gov]
From: Johnson, Yvonne W
Sent: Thur 10/26/2017 9:57:47 PM
Subject: latest version of SESARM 2017 Fall _wTPs
SESARM 2017 Fall _wTPs_oct 24.pptx

Here is the latest version of the SESARM slides which incorporate Mike's comments sent on 10/25. I will let you all decide if you take any of the EO slides out (I added all that Vera sent) and she is planning to send one more.

To: Johnson, Yvonne W[Johnson.Yvonnew@epa.gov]
Cc: Wood, Anna[Wood.Anna@epa.gov]
From: Kornylak, Vera S.
Sent: Tue 9/19/2017 7:05:43 PM
Subject: NACAA 2017 Fall Full Deck w_TPs_sept 18+Vera.pptx
NACAA 2017 Fall Full Deck w_TPs_sept 18+Vera.pptx

Yvonne:

I made changes to

-EE slide 12 – added a talking point on mitigation plans and edited the bullet on that slide

-RH slide 21 – added update on the litigation to the talking points

I separately sent to you that I think should be included as part of Anna's packet:

-AAPCA EE meeting follow-up talking points

-Recently updated SIP paper

Vera

Vera Kornylak || Senior Policy Advisor

Air Quality Policy Division || OAQPS

919-541-4067 || kornylak.vera@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Thur 5/25/2017 11:23:21 PM
Subject: RE: Another pesky request re sesarm
NACAA 2017 Spring Full Deck w_TPs.pptx
2017 Spring ADD Meeting_EOs_FINAL_TPs.pptx
2017 Spring ADD Meeting_SIP Management Session_FINAL_TPs.pptx
Air Dir Mtg Spring 2017 Agenda V2 170510.docx

Attached is the SESARM agenda and the NACAA, ADD EO, and ADD SIP presentations. Info from Lynora: 40-45 minutes for slides and 15-20 minutes for discussion on:

NAAQS Impl Update
SSM
NSR & TV permitting
Specs for SIPs
Regional Haze
Transport

Thank you,

Yvonne W. Johnson
Special Assistant to the Director
Air Quality Policy Division
Office of Air Quality Planning & Standards
U.S. Environmental Protection Agency
919-541-3921
johnson.yvonnew@epa.gov

-----Original Message-----
From: Wood, Anna
Sent: Thursday, May 25, 2017 6:26 PM
To: Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>
Subject: Another pesky request re sesarm

Will you please send me the following:
NACAA slide deck with talkers
ADD slides re specs for sips with talkers ADD EO slides with talkers Latest version of SESARM agenda and notes/input you got from Lynorae- I need to work on my slides this weekend- thx!!

Sent from my iPhone

Region 4 Grants/Planning Meeting
June 6-8, 2017
Atlanta, Georgia
Agenda

Tuesday, June 6, 2017 Morning Session		
8:00 a.m.	**SESARM Board of Directors Meeting** *Rhonda Thompson (SC), Chair*	Agenda to be distributed later
9:00 a.m.	**Small Group Meeting** *State directors* *Local agency representatives* *EPA Region 4 APTMD staff* *Anna Wood (EPA OAQPS) (invited)*	TSA Lean Initiative discussion Other topics to be distributed later
10:15 a.m.	**Break**	
10:30 a.m.	**Small Group Meeting (cont.)**	
11:30 a.m.	**Lunch**	

Tuesday, June 6, 2017 Afternoon Session		
12:00 noon	**Registration**	
1:15 p.m.	**Welcome** *John Hornback (Metro 4/SESARM)*	• Introductions • Agenda review • Logistics
1:30 p.m.	**Standards and Implementation** *Anna Wood (OAQPS)*	• NAAQS development updates • Implementation discussions • Regional haze expectations and schedule • Transport Issues and analyses • Other Issues • State/Local feedback/Q&A
2:30 p.m.	**Break**	
3:00 p.m.	**Southeast Wildfire Experiences** *State and Local Agencies*	• Experiences and lessons learned from 2016 fires • Implications for 2017 and beyond
3:30 p.m.	**Exceptional Events** *Gregg Worley, Todd Rinck (APTMD)* *Anna Wood, Beth Palma, Ben Gibson (OAQPS)*	• When exceptional event demonstrations are needed • Expectations for demonstrations • State/Local feedback/Q&A
4:15 p.m.	**Meeting adjourns for the day**	
4:30 p.m.	**Metro 4 Board of Directors and Membership Meeting** *Jerry Campbell (Hillsborough County FL), President*	Agenda to be distributed later

Wednesday, June 7, 2017 Morning Session		
8:30 a.m.	**EPA Region 4 APTMD Director Welcome and Report** *Beverly Banister (APTMD)*	• Region 4 updates & staff changes • National priorities and implications for agencies • Budget updates for 2017 and 2018 • State/Local feedback/Q&A
9:00 a.m.	**Modeling Support and Updates** *Gregg Worley, Todd Rinck and staff (APTMD)*	• Summary of SO_2 Data Requirements Rule modeling • Appendix W status • State/Local feedback/Q&A
9:30 a.m.	**Monitoring Update for Region 4** *Gregg Worley, Todd Rinck (APTMD)* *Laura Ackerman (SESD)*	• 2017 annual network plan submittal • Air monitoring workshop follow-up • Feedback on monitoring equipment replacement efforts – discussion and feedback • PAMS update • State/Local feedback/Q&A
10:15 a.m.	**Break**	
10:45 a.m.	**TSAs and Monitoring Data Quality** *Jeaneanne Gettle, Laura Ackerman (SESD)* *DeAnna Oser, Georgia* *TBD, Forsyth County NC*	• Report on status of TSA Lean Initiative • Feedback from participants • Update on process improvements • Next steps • State/Local feedback/Q&A
11:15 a.m.	**Stationary Source Regulatory Update – Clean Air Act Sections 111, 112, and 129** *Beverly Spagg, Ken Mitchell, Todd Russo, Dick Dubose & Staff (APTMD)*	• Placeholder • State/Local feedback/Q&A
11:45 a.m.	**Lunch**	

Wednesday, June 7, 2017 Afternoon Session		
1:30 p.m.	**Great Smoky Mountains Water Quality Impairment and Air Emissions Linkages** *Jim Renfro, National Park Service*	• Observations on atmospheric deposition and stream acidification • Modeling and long-term prognosis • Collaboration with states • State/Local feedback/Q&A
2:30 p.m.	**Break**	
3:00 p.m.	**Smoke Summit III** *Scott Davis and Rick Gillam (APTMD)* *State participants*	• Recap of recent workshop • Next steps • State/Local feedback/Q&A
3:30 p.m.	**NAAQS and SIPs Updates and Issues for Region 4** *Scott Davis and Lynorae Benjamin (APTMD)*	• NAAQS updates • SO_2 designations update • 4-Year SIP plans update • State/Local feedback/Q&A
4:30 p.m.	**Meeting adjourns for the day**	
5:30 p.m.	**Evening reception and cookout** *Hosted by Carol Kemker and family*	Directions to Carol's house to follow. Status of likely attendance requested.

Thursday, June 8, 2017 Morning Session		
8:30 a.m.	**Grants and Funding** *Carol Kemker, Stuart Perry & Staff (APTMD)*	• Budget status for FY17 • FY 2018 funding outlook • Grant allocation process • Grant funding status and next steps • Grant policy updates/initiatives • Scheduling, work plan expectations, and holdbacks • MJO funding update for Metro 4 and SESARM • State/Local feedback/Q&A
9:15 a.m.	**Ports Initiative Update** *Amber Davis (APTMD)*	• Ports Initiative update • State/Local feedback/Q&A
9:30 a.m.	**Permitting Update** *Scott Davis, Heather Ceron (APTMD)*	• Permit program updates • Report from recent Permit Workshop • State/Local feedback/Q&A
10:30 a.m.	**Break**	
11:00 a.m.	**State/Local Agency Sharing –** *APTMD and State/Local agencies*	• Roundtable of other issues facing states/locals
11:30 a.m.	**Closing Remarks** *John Hornback, Doug Carson*	• Training update – 2017 status and 2018 needs • Future program manager workshops • Future director meetings – dates/locations • Member agency special project needs
12:00 p.m.	**Meeting concludes**	

NAAQS AND OTHER IMPLEMENTATION UPDATES

Anna Marie Wood, Director
Air Quality Policy Division
OAQPS, U.S. EPA
NACAA Spring Meeting 2017

OVERVIEW

- NAAQS Implementation Updates
  - Ozone
  - Sulfur Dioxide (SO_2)
  - Fine Particulate Matter ($PM_{2.5}$)
  - Lead
- Exceptional Events
- Transport
- Regional Haze
- Startup, Shutdown, and Malfunction (SSM) Policy for SIPs and SIP Call
- NSR and Title V Permitting Updates
- Reducing the SIP Backlog
- State Plan Electronic Collections System for SIPs

NAAQS Reviews: Status Update

(March 2017)

	Ozone	Lead	Primary NO_2	Primary SO_2	Secondary (Ecological) NO_2, SO_2, PM[1]	PM[2]	CO
Last Review Completed (final rule signed)	Oct. 2015	Sept 2016	Jan 2010	Jun 2010	Mar 2012	Dec 2012	Aug 2011
Recent or Upcoming Major Milestone(s)[3]	TBD[4]	TBD[4]	<u>Jan 2016</u> Final ISA <u>Sep 2016</u> 1st Draft PA <u>Spring 2017</u> Final PA	<u>Dec 2016</u> 2nd Draft ISA <u>Feb 2017</u> REA Planning Document <u>March 2017</u> CASAC review of Draft ISA and REA Planning Document	<u>Jan 2017</u> Final IRP <u>Spring 2017</u> CASAC review of 1st Draft ISA	<u>Dec 2016</u> Final IRP <u>Winter 2017/2018</u> 1st draft ISA REA Planning Document	TBD[4]

Additional information regarding current and previous NAAQS reviews is available at:
http://www.epa.gov/ttn/naaqs/

[1] Combined secondary (ecological effects only) review of NO_2, SO_2, and PM
[2] Combined primary and secondary (non-ecological effects) review of PM
[3] IRP – Integrated Review Plan; ISA – Integrated Science Assessment; REA – Risk and Exposure Assessment; PA – Policy Assessment
[4] TBD = to be determined

Anticipated NAAQS Implementation Milestones

(March 2017)

Pollutant	Final NAAQS Date	Designations Effective	Infrastructure SIP Due	Attainment Plans Due	Attainment Date
$PM_{2.5}$ (2006)	Oct 2006	Dec 2009	Oct 2009	Dec 2014	Dec 2015 (Mod) Dec 2019 (Ser)
Pb (2008)	Oct 2008	Dec 2010-2011	Oct 2011	June 2012-2013	Dec 2015-2019
$PM_{2.5}$ (2012)	Dec 2012	Apr 2015	Dec 2015	Oct 2016 (Mod)	Dec 2021 (Mod) Dec 2025 (Ser)
NO_2 (2010) (primary)	Jan 2010	Feb 2012	Jan 2013	N/A	N/A
SO_2 (2010) (primary)	June 2010	Oct 2013, Sept 2016 (+2 rounds)	June 2013	April 2015, March 2018 (2019, 2022)	Oct 2018, Sept 2021 (2023, 2026)
Ozone (2008)	Mar 2008	July 2012	Mar 2011	Mid 2015-2016	Mid 2015-2032
Ozone (2015)	Oct 2015	Dec 2017	Oct 2018	Dec 2020-2021	2020-2037

2008 Ozone NAAQS Implementation

- **Final Implementation of the 2008 NAAQS for Ozone: State Implementation Plan Requirements Rule** published March 6, 2015 (80 FR 12264)
  - Provides interpretive rules and guidance on nearly all aspects of the attainment planning requirements for designated nonattainment areas
  - Revoked the 1997 NAAQS (effective April 6, 2015) and established anti-backsliding requirements

- Key implementation dates for nonattainment areas:
  - Emissions inventories, emissions statement rules and RACT SIPs due July 2014
  - Attainment plans and demonstrations due July 2015 (Moderate) or July 2016 (Serious and above)
  - Marginal area attainment date July 20, 2015 (attainment determined by 2012-2014 air quality data)
  - Moderate area attainment date July 20, 2018 (2015-2017 air quality data)

2008 Ozone NAAQS Implementation: Litigation

- South Coast Air Quality Management District and environmental petitioners (Sierra Club *et al.*) challenged various aspects of the 2008 Ozone NAAQS SIP Requirements Rule, including creditability of reasonable further progress (RFP) control measures, revocation of 1997 NAAQS and application of regulatory anti-backsliding requirements (final briefs submitted; oral arguments schedule TBD)

- In response to a complaint filed by environmental petitioners, the EPA found that 15 states and the District of Columbia failed to submit certain SIP revisions required under the 2008 ozone NAAQS (82 FR 9158; February 3, 2017).
  - The finding of failure to submit action gives formal notice to affected parties, and establishes deadlines by which they either must submit complete SIP revisions or become subject to mandatory sanctions.
  - Petitioners further alleged that EPA failed to take final action on SIP submittals by various states under the 1997 and 2008 ozone NAAQS.
  - EPA entered into a Consent Decree with the petitioners on January 19, 2017, which sets deadlines for EPA to complete final actions on SIP submittals by various dates ranging from June 2017 to July 2018.

Progress on Ozone NAAQS Attainment

(as of March 2017)

	1997 NAAQS (2004 Designations)	2008 NAAQS (2012 Designations)
Initial Nonattainment Areas	115	46
Areas Redesignated to Attainment	80 (prior to revocation)	6
Current Nonattainment Areas	35	40
Clean Data Determinations	26	18*
Redesignation Substitutes	2	0
Reclassifications to Higher Classification	N/A after revocation	13

*Includes 15 Marginal area determinations of attainment by the attainment date and 3 Moderate area clean data determinations.

2015 Ozone NAAQS: Implementation-Related Rules/Guidance/Activities

- **Final National Ambient Air Quality Standards for Ozone Rule** signed October 1, 2015 (40 FR 65292), revising the primary and secondary 8-hour ozone standards to 0.070 ppm
  - Litigation pending on the level of the standard (oral arguments scheduled for April 19, 2017)

- **Proposed Rule: Implementation of the 2015 NAAQS for Ozone: Nonattainment Area Classifications and State Implementation Plan Requirements** published November 17, 2016 (81 FR 81276)
  - Can be found at https://www.epa.gov/ozone-pollution/implementation-2015-national-ambient-air-quality-standards-naaqs-ozone-state
  - Proposed rule comment period closed February 13, 2017; timing of final rule TBD

- PSD permitting tools/guidance:
  - Final update to Guideline on Air Quality Models (Appendix W to 40 CFR Part 51)
  - Guidance on compliance demonstration tools:
    - Ozone and $PM_{2.5}$ significant impact levels (SILs) (posted for comment in August 2016)
    - Model emissions rates for precursors (MERPs)

- Update to transportation conformity guidance specific to nonattainment areas for 2015 NAAQS (Fall 2017)

Intended Schedule for 2015 Ozone NAAQS Implementation Rules/Guidance/Tools

Action	After NAAQS Promulgation	(Actual) and Planned Dates
EPA proposes nonattainment area SIP rules/guidance (including area classifications thresholds, SIP due dates, and nonattainment NSR provisions)	12 months	(November 2016)
EPA finalizes designations, classifications, and nonattainment area SIP rules/guidance	24 months	October 2017
States submit infrastructure and transport SIPs	36 months	October 2018
States submit attainment plans	5-6 years	2020-2021
Nonattainment area attainment dates (Marginal – Extreme)	5-22 years	2020-2037

2015 Ozone NAAQS Implementation Rule Proposal: Key Topics

- Nonattainment area classification thresholds
  - Proposed the current “percent-above-the-standard” classification thresholds method. Moderate=81ppb
- Revocation of the 2008 Ozone NAAQS - 2 options
  - Opt 1: revoke the 2008 NAAQS for all areas and purposes 1 year after designations are effective (historical ozone approach)
  - Opt 2: revoke the 2008 NAAQS only in areas attaining the 2008 NAAQS at time of its revocation, and later for areas upon redesignation to attainment for the 2008 or 2015 NAAQS (similar to $PM_{2.5}$ approach)
- Submitting nonattainment area and OTR SIP elements
  - Clear listing of required SIP elements
  - How to submit “certification” SIPs

2015 Ozone NAAQS: Anticipated Timeline for Designations Process

Milestone	Date
The EPA promulgates 2015 Ozone NAAQS rule	October 1, 2015
The EPA issues designations guidance	February 25, 2016
Air agencies submit exceptional events demonstrations for data years 2014-2015	No later than the date recommendations are due to EPA (October 1, 2016)
States and tribes submit recommendations for ozone designations (and exceptional events demonstrations for data years 2014-2015) to EPA	2016 Exceptional Events Rule revisions changed the due date from October 1, 2016 to November 29, 2016
The EPA notifies states and tribes concerning any intended modifications to their recommendations (120-day letters)	No later than June 2, 2017 (120 days prior to final ozone area designations)
The EPA publishes public notice of state and tribal recommendations and the EPA's intended modifications, if any, and initiates 30-day public comment period	On or about June 9, 2017
End of 30-day public comment period	On or about July 10, 2017
States and tribes submit additional information, if any, to respond to the EPA's modification of a recommended designation	No later than August 7, 2017
The EPA promulgates final ozone area designations	No later than October 1, 2017

2010 SO_2 NAAQS Implementation

- EPA revised **Primary NAAQS for Sulfur Dioxide (SO_2) standard** on June 3, 2010 to 75 ppb/1-hour (75 FR 35520)

- EPA designated 29 areas as nonattainment on July 25, 2013 (Round 1)
  - **Guidance for 1-hr SO_2 NAAQS NAA SIP Submissions** was issued on April 23, 2014
  - Attainment plans for the 29 areas were due April 4, 2015
  - EPA issued findings of failure (FFS) to submit attainment plans for 16 areas in 11 states, effective April 18, 2016 (81 FR 14736; published March 18, 2016)

- EPA is required to promulgate a Federal Implementation Plan (FIP) if a state does not submit, and EPA does not approve the required SIPs within 24 months of the effective date of the FFS (i.e., April 18, 2018)

- EPA is working with affected states to develop SIPs

2010 SO_2 NAAQS Designations

- Consent decree entered on March 2, 2015, by U.S. District Court for Northern California in *SIERRA CLUB and NATURAL RESOURCES DEFENSE COUNCIL v. EPA* "triggered" the following deadlines:
  - July 2, 2016 - The EPA must complete a round of designations for 61 areas associated with approximately 64 EGUs in 24 states and any undesignated areas with violating monitors ("Round 2" designations)
  - December 31, 2017 - The EPA must complete an additional round of designations for any area a state has not established a new monitoring network by January 1, 2017 per the provisions of the SO_2 Data Requirements Rule
  - December 31, 2020 - The EPA must complete designations of all remaining, undesignated areas (expected to be areas where states elected to monitor per the provisions of the DRR)

2010 SO_2 Designations Due on July 2, 2016 Under Consent Decree

- On June 30, 2016, EPA finalized designations for 61 areas for "Round 2":
  - Areas where there are sources (electric power plants) that as of March 2, 2015, have not been "announced for retirement," and
  - Areas that meet one of the following emissions thresholds:
    - 16,000 tons of emitted in 2012 or
    - 2,600 tons of SO_2 emitted in 2012 with an average emission rate of at least 0.45 pounds of SO_2 per mmBtu
  - Areas where 2013-15 data indicate monitored violations – only Hawaii County, HI – which was determined to be an Exceptional Event

- These designations included 4 nonattainment areas, 41 unclassifiable/attainment areas, and 16 unclassifiable areas

SO_2 NAAQS Data Requirements Rule: Milestones

- **January 15, 2016:** Deadline for air agency to identify applicable sources (i.e., those exceeding threshold and other sources for which air quality will be characterized)
  - EPA notified states in March 2016 that review of source lists was complete. In a few cases, EPA added sources to characterization list
- **July 1, 2016:** Deadline for air agency to specify (for each applicable source) whether it will monitor air quality, model air quality, or establish an enforceable limit
  - Air agency also accordingly submits a revised monitoring plan, modeling protocols, or descriptions of planned limits on source emissions to less than 2,000 tpy, or documentation that a source has shut down
- **January 2017**
  - January 1: Deadline for new monitoring sites to be operational
  - January 13: Deadline for air agency to submit modeling analyses or documentation of emission limits/shut down
- **Early 2020:** Monitoring sites will have 3 years of quality-assured data which must be submitted to EPA

- EPA's website has recently been updated with state submittals associated with these milestones and related correspondence with EPA
  - https://www.epa.gov/so2-pollution/final-data-requirements-rule-2010-1-hour-sulfur-dioxide-so2-primary-national-ambient

Intended Schedule for Area Designations for 2010 SO_2 NAAQS Due on December 31, 2017 (Round 3)

Milestone	Date
States and tribes may submit updated recommendations and supporting information for area designations to the EPA	No later than January 13, 2017
States and tribes submit modeling analyses pursuant to SO2 Data Requirements Rule	No later than January 13, 2017
States submit exceptional events demonstrations for event-influenced SO2 monitoring data from 2015-2016	No later than July 14 , 2017
The EPA notifies states and tribes concerning any intended modifications to their recommendations (120-day letters)	on/about August 14, 2017 (no later than 120 days prior to final designations)
The EPA publishes public notice of state and tribal recommendations and the EPA's intended modifications and initiates 30-day public comment period	on/about August 24, 2017
End of 30-day public comment period	on/about September 24, 2017
States and tribes submit additional information, if desired, to demonstrate why an EPA modification is inappropriate	No later than October 13, 2017
The EPA signs notice promulgating final SO2 area designations for Round 3	on/about December 14, 2017 (can be no later than December 31, 2017)

$PM_{2.5}$ NAAQS Implementation: SIP Requirements Rule

- **$PM_{2.5}$ NAAQS SIP Requirements Rule** finalized on August 24, 2016 (81 FR 58010) provided framework for planning requirements for 2012 and future $PM_{2.5}$ NAAQS and informs implementation for areas still violating 1997 and/or 2006 $PM_{2.5}$ NAAQS

- November 2016 EPA issued draft **$PM_{2.5}$ Precursor Demonstration Guidance**
  - Recommends technical approaches for precursor demonstrations to assess whether air quality impact from a particular precursor can be considered to be insignificant in a given area
  - Comment period extended to March 31, 2017

- South Coast Air Quality Management District filed suit challenging two aspects of the rule:
  1. Requirement that emissions reductions for RFP come from sources within the nonattainment area (consistent with past court decision)
  2. Lack of explicit "de minimis" source category exclusion for Reasonably Available Control Measures (RACM) and Best Available Control Measures (BACM)
  - Petitioner's brief due on April 4, 2017; EPA response brief due June 6, 2017

2006 $PM_{2.5}$ NAAQS Implementation

- In December 2016, EPA proposed:
  - Determinations of attainment for 7 areas
  - Findings of failure to attain by the December 31, 2015 attainment date, and reclassification to Serious for 4 areas
  - The action is a mandatory requirement under the CAA and will fulfill obligations included in consent decrees resulting from two lawsuits.

- Serious area attainment date is December 31, 2019
  - Extension up to December 31, 2024 is possible if cannot demonstrate attainment by 2019. Requires Most Stringent Measures in any state.

- EPA plans to take final action this year on a number of submitted Moderate area plans and will continue to work with states developing Serious area plans to address air quality challenges.

2012 $PM_{2.5}$ NAAQS Implementation

- December 14, 2012 revised the $PM_{2.5}$ NAAQS primary annual $PM_{2.5}$ standard to 12µg/m^3 (78 FR 3086)
  - Nine Moderate nonattainment areas were designated in 2015
  - Moderate area attainment plan due date - October 2016
  - Moderate area attainment date - December 31, 2021
  - Serious area attainment date - December 31, 2025

Progress on $PM_{2.5}$ NAAQS Attainment

(as of March 2017)

	1997 $PM_{2.5}$ (2005 Designations)	2006 $PM_{2.5}$ (2009 Designations)	2012 $PM_{2.5}$ (2015 Designations)
Initial Nonattainment Areas	39	32	9
Areas Redesignated to Attainment	31	16	0
Current Nonattainment Areas	8	16	9
Clean Data Determinations	5	8	1
Proposed Redesignations	0	0	0

Lead NAAQS Implementation Update

- In 2008, EPA strengthened the standard and changed the level to $0.15 \mu g/m^3$
  - EPA initially designated 22 areas as nonattainment:
    - 16 areas were designated nonattainment effective Dec. 31, 2010
    - 5 additional areas were designated nonattainment effective Dec. 31, 2011
    - 1 area was designated nonattainment effective October 3, 2014
- As of January 2017, 20 areas remain in nonattainment:
  - For most of the nonattainment areas, the Pb emissions and monitored concentrations are declining due to facility closures or implemented control measures.
- On September 16, 2016, EPA completed its review of the Pb NAAQS and issued a decision to retain the existing 2008 standards without revision

Exceptional Events

- On September 16, 2016, the EPA finalized the **2016 Revisions to the Exceptional Events Rule**, which address issues raised by stakeholders and increase the administrative efficiency of the Exceptional Event demonstrations process
  - https://www.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
  - Rule effective date was September 30, 2016
  - Published in Federal Register on October 3, 2016 (81 FR 68216)
  - NRDC/Sierra Club filed a Petition for Review on December 2, 2016 (petitioners' brief due 5/17/17, EPA response due 8/17/17)

- General Exceptional Events Rule Background
  - Establishes procedures and criteria for identifying and evaluating air quality monitoring data affected by exceptional events
  - Provides a mechanism by which air quality data can be excluded from regulatory decisions and actions
  - Applies to all criteria pollutants and NAAQS and all event types to which the rule applies
  - Applies to all state air agencies, to (delegated) local air agencies, to tribal air agencies that operate air quality monitors that produce regulatory data and to federal land managers/federal agencies if agreed by the state
  - Affects design value calculations, NAAQS designation decisions, attainment determinations, and State / Tribal / Federal Implementation Plan (SIP/FIP/TIP) development

Exceptional Events Rule Revisions

- Clarify the types of determinations and actions to which the authorizing statutory authority in Clean Air Act (CAA) section 319(b) applies
- Return to the core statutory elements of CAA section 319(b)
- Clarify "not reasonably controllable or preventable" criteria
- Clarify high wind elements currently addressed in guidance
- Codify requirements for the content and organization of exceptional events submittals
- Remove "general schedule" deadlines for data flagging and demonstration submittal

Exceptional Events Rule Revisions and Guidance

- New fire-related rule language and preamble text
- Mitigation Regulatory Requirements
- Other provisions
  - Address who may submit a demonstration
  - Event aggregation
  - Identified in preamble intended timelines for EPA response

- Final Wildfire/Ozone Exceptional Events Implementation Guidance

Exceptional Events Implementation: Stakeholder Feedback

- November 2016 implementation workshops for states and tribes (Denver – 11/8/16; Dallas – 11/30/16)
- General feedback
  - Participants were generally pleased with both the rule revisions and the content of the workshop
  - Participants requested further guidance and similar implementation workshops (both for exceptional events and other EPA programs) and asked for follow-up communication and outreach workshops/webinars following promulgation
  - Participants asked that EPA continue to find ways to reduce the transaction costs in exceptional events demonstrations
  - Participants called for continued EPA communication and support with more tools and examples as they become available

Exceptional Events Implementation: Available Resources

- Exceptional Events Website at http://www2.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
- Quick reference guide for exceptional events demonstrations
- Examples of reviewed exceptional event submissions
- Best practices documents
- Links to publicly available support information and tools
- Links to rule and guidance resources
  - Final rule
  - Final wildfire/ozone guidance
  - Fact sheets
  - 2013 interim guidance documents

Exceptional Events Implementation: Next Steps

- The 2016 rule revisions and final wildfire/ozone guidance were needed first steps, but efficient and coordinated implementation is critical.
- What is next?
- Additional Implementation Materials
  - Revisions to 2013 *Interim Exceptional Events Guidance Documents*
  - Stratospheric Ozone Intrusion Document
  - Alternate Paths for Data Exclusion Document
  - Prescribed Fire/Ozone Document
- Continued development of exceptional events tools
  - Templates
  - Website updates
  - AQS modifications to reflect rule revisions guided by feedback from newly created AQS workgroup
  - Standardized metrics and tracking
  - Targeted efforts with FLMs – communications and tools
  - Best practices for multi-state exceptional events demonstrations

Interstate Transport SIP Obligations

- The CAA's "Good Neighbor Provision" [section 110(a)(2)(D)(i)] obligates states to prohibit emissions that will contribute significantly to downwind nonattainment or interfere with maintenance of any NAAQS in another state

- States must submit Good Neighbor SIPs within 3 years of promulgation of a new or revised NAAQS

- EPA must promulgate a FIP for a state within 2 years of finding that the state failed to submit a complete Good Neighbor SIP or if EPA disapproves the SIP

Framework for Interstate Transport

- EPA's framework provides a roadmap for addressing the Good Neighbor Provision
  - This familiar framework has been used to address transported air pollution for ~20 years (*e.g.,* NO_X SIP Call, CAIR, CSAPR) with updates in response to stakeholder feedback and court decisions
  - EPA most recently applied this framework in the CSAPR Update for the 2008 ozone NAAQS

- The framework has four overarching steps:
  - Step 1: Identify downwind areas that are expected to have problems attaining and/or maintaining the NAAQS
  - Step 2: Determine which upwind states are "linked" to these downwind areas
  - Step 3: For linked states, quantify the level of upwind emission reductions that are needed to address the good neighbor obligation
  - Step 4: Implement reductions via enforceable requirements

Cross-State Air Pollution Rule

- CSAPR (finalized July 2011) addresses interstate transport obligations for the 1997 ozone NAAQS (and the 1997 and 2006 $PM_{2.5}$ NAAQS)
- CSAPR Update (finalized September 7, 2016) updates CSAPR ozone season program by addressing summertime transport of ozone for the 2008 ozone NAAQS in the eastern US
  - Covers 22 eastern states (see map on next slide) and sets power sector ozone season NO_X emission budgets for each covered state starting with the 2017 ozone season (May 1, 2017).
  - Establishes a new ozone season NO_X allowance trading program for CSAPR Update states
  - Facilitates a smooth shift from original CSAPR by transitioning a limited number of banked allowances for compliance
  - Responds to the July 2015 D.C. Circuit remand of CSAPR Phase 2 ozone season emission budgets for 11 states
  - Additional information at http://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update

Key Implementation Dates and Actions for the 2008 Ozone NAAQS

- Outstanding Good Neighbor obligations for the 2008 ozone NAAQS
  - CSAPR Update was a partial remedy for 21 eastern states (full remedy for TN)
  - The statutory date to promulgate a full FIP for KY passed in 2016 and the statutory full FIP deadline will expire for a number of other states starting in August 2017
  - CSAPR Update did not "FIP" western states or otherwise provide their interstate transport obligation (EPA is subject to statutory deadlines to promulgate FIPs for 4 western states)
    - 8/2017 statutory FIP deadline for CA and NM
    - 11/2018 statutory FIP deadline for UT
    - 3/2019 statutory FIP deadline for WY based on SIP disapproval, effective 3/6/2017 (82 FR 9142)
- These obligations can be remedied via SIPs or FIPs

Key Implementation Dates for the 2015 Ozone NAAQS

- **10/2015**: Revised ozone NAAQS promulgated
  - Implementation memo committed to issuing transport data (Air Quality Modeling NODA in December 2016 – see following slide)
- **10/2017**: Initial Area Designations (based on 2014-2016 data)
- **10/2018**: Good Neighbor SIPs due
- **12/2020**: Marginal attainment deadline; Moderate area attainment SIPs due
  - Assumes effective date of designations is December 31, 2017 (or later) such that attainment year would be 2020
- **12/2023**: Moderate attainment deadline
  - Using same assumptions above, attainment year would be 2023
  - Note that clean data in 2023 could be used for an extension

Implementing Good Neighbor Provision for 2015 Ozone NAAQS

- EPA recognizes…
  - States have expressed a desire for regulatory certainty when complying with CAA requirements, planning for emissions reductions and planning for attainment
  - The CAA envisions a SIP-led process even while states have made clear that they need information and direction from EPA to understand how to compose approvable and timely transport SIPs to address regional (multi-state) air quality problems
  - While states have asked for additional information in developing SIPs, they can ultimately use any available information to demonstrate that they are meeting their interstate transport obligations

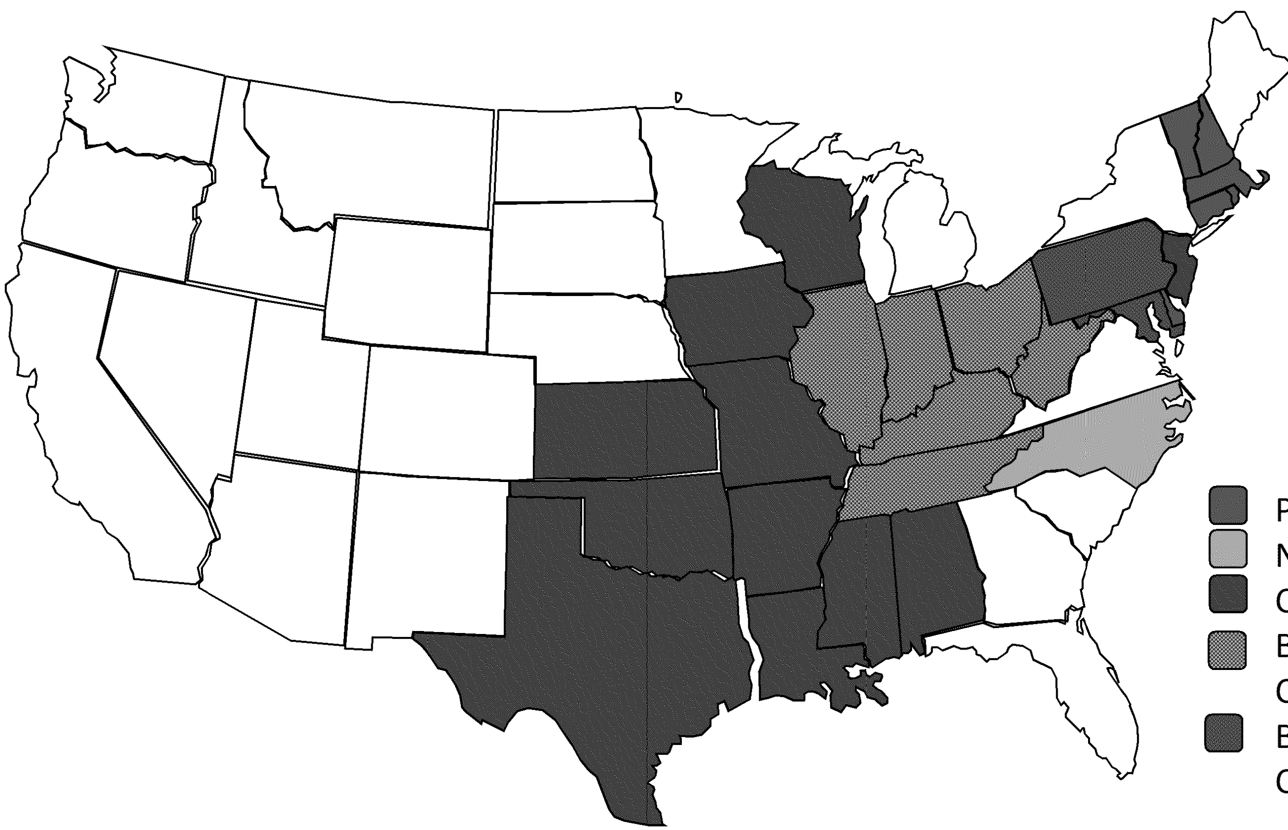
Key Implementation Dates for the 2015 Ozone NAAQS

- In December 2016, EPA shared preliminary interstate ozone transport modeling information through a Notice of Data Availability (NODA) (82 FR 1733, January 6, 2017), which:
  - was developed considering stakeholder feedback
  - intends to help states prepare for (or start discussions on) transport SIPs for the 2015 ozone NAAQS
  - uses the first 2 steps of the CSAPR framework to provide preliminary interstate ozone transport information, including projected nonattainment and maintenance receptors for 2023
  - requests feedback on the datasets used in the modeling efforts and on the projection and modeling approach
  - Comment period closed on April 6, 2017

Clean Air Act Section 176A

- On January 11, 2017, EPA signed a proposed action to deny a CAA section 176A petition from several Northeastern states that requested that EPA expand the Ozone Transport Region by adding 9 additional states
  - EPA received the petition in 2013; EPA's statutory deadline to respond was in June 2015
  - EPA is subject to two consent decrees obligating EPA to finalize action by October 27, 2017
  - Public hearing held on April 13 in DC (original date was March 14, but postponed due to weather). Comment period extended until May 15, 2017

176A Petition and CSAPR Update States



Petitioning State
Named Upwind State
CSAPR Update State
Both Named State and CSAPR Update State
Both Petitioning State and CSAPR Update State

Clean Air Act Section 126

- Under CAA Section 126, any state (or political subdivision) may petition EPA for a finding that a major source or group of stationary sources emits or would emit any pollutant in violation of the Good Neighbor Provision

- EPA is required by statute to act on the petition within 60 days. EPA generally extends this deadline by 6 months as authorized by Section 307(d)(10) of the Act.
  - EPA has generally found that the 60-day period is insufficient to develop a proposal, take comment, determine whether to grant, and develop a remedy if granted
  - Even with the 6-month extension, these deadlines are extremely difficult to meet

- Where EPA finds that a source is violating the Good Neighbor Provision, EPA generally promulgates a compliance schedule, which the CAA says can be up to 3 years with increments of progress

Clean Air Act Section 126

Petitioning State	Response Deadlines	Named EGU Sources	Ozone NAAQS Cited
CT*	1/25/17	Brunner Island, PA	2008
DE (4 petitions)	3/5/17 4/7/17 7/9/17 8/3/17	1. Brunner Island, PA 2. Harrison, WV 3. Homer City, PA 4. Conemaugh, PA	2008 and 2015
MD	7/15/17	36 EGUs at 19 facilities in IN, KY, OH, PA and WV	Emphasized 2008

*On March 9, 2017, CT provided its notice of intent to sue for EPA's failure to respond to its 126 petition by the January 2017 deadline. Sierra Club submitted an NOI on the same petition on March 10, 2017.

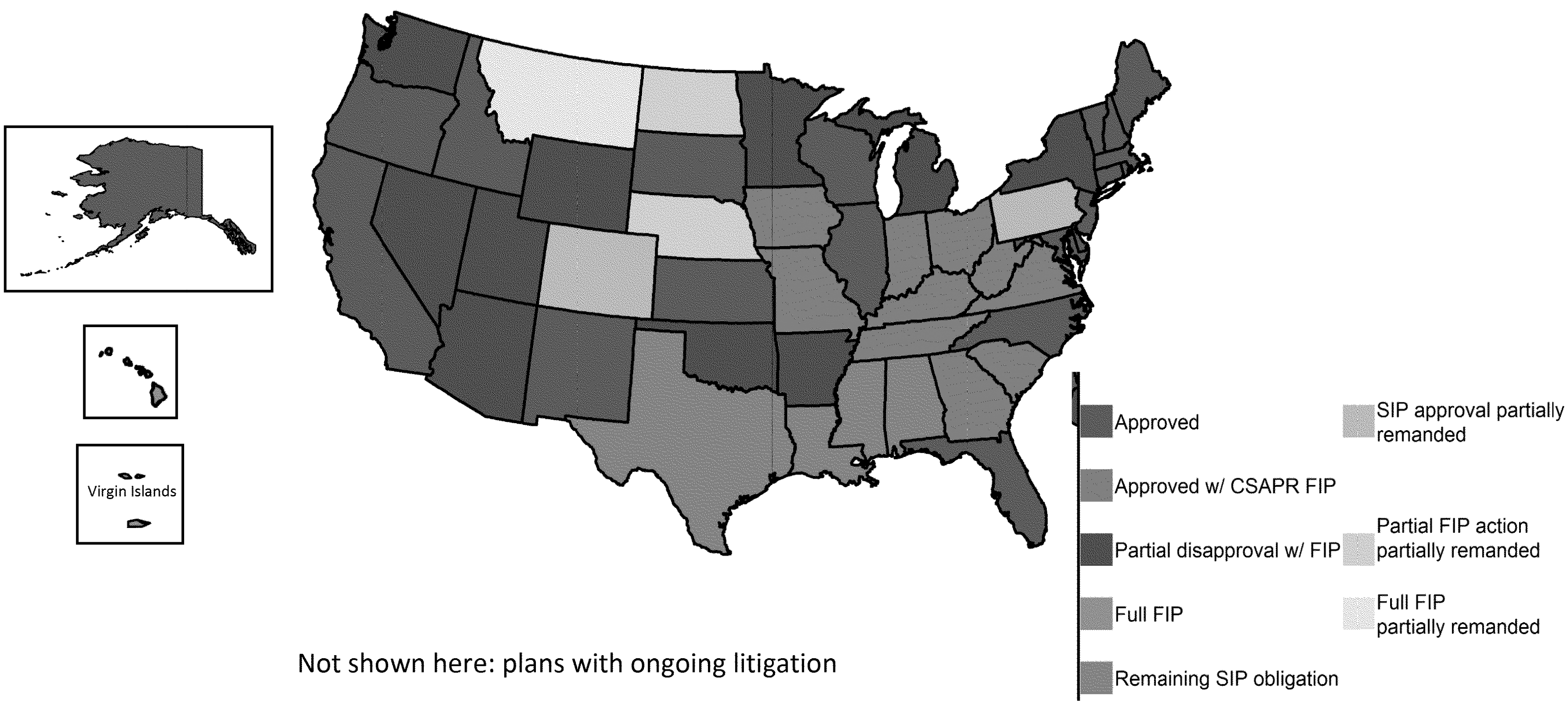
Regional Haze: Status of Actions from First Implementation Period

- Most states have complete plans in place, but there are outstanding obligations in a few states

- Litigation lingers in several states – with challenges for:
  - CSAPR reliance for EGU BART
  - FIPs (from states, affected sources, and environmental groups)
  - Disapproved SIPs (by states and affected sources) and approved SIPs (by environmental groups)

- Other RH related program activities and issues are being considered and addressed:
  - Actions on 5-year progress reports
  - Options for visibility protection iSIPs
  - July 28, 2015, CSAPR D.C. Circuit opinion and potential interactions with RH SIPs/FIPs

Regional Haze: Status of Actions from First Implementation Period



Not shown here: plans with ongoing litigation

Regional Haze Looking Forward: Planning for the Next Cycle of SIPs

- Outreach:
  - EPA conducted outreach with RPOs and state and tribal air agencies during 2014 and 2015 to hear what worked well and what could be improved based on lessons learned from the first planning period.
  - This outreach led to recent rule revisions (below) and also to a Draft Guidance Document (next slide).

- Rule revisions were finalized on January 10, 2017 (82 FR 3078):
  - Provided certain clarifications to reflect the Agency's long-standing interpretations of the 1999 Regional Haze rule
  - Shifted the due date for the next round of comprehensive planning SIPs to July 2021; will not prevent states from submitting SIPs earlier
  - Changed the schedule and process for submitting 5-year Progress Reports
  - Revised aspects of RAVI (Reasonably Attributable Visibility Impairment) provisions
  - Note: several petitions for review and petitions for reconsideration of the rule have been received

Regional Haze Looking Forward: Planning for the Next Cycle of SIPs (con't)

- On July 8, 2016 (81 FR 44608), EPA released draft guidance for two key aspects of the program:
  - 1) Visibility Tracking – Tracking visibility progress based on impacts from controllable, anthropogenic emissions instead of all sources
  - 2) Reasonable Progress (RP) Guidelines – Guidance for evaluating the statutory factors and making decisions on RP controls

- EPA is currently considering public comments as we work to finalize the guidance document.

- Timing for guidance document: TBD

Response to SSM Petition, Final Policy and SIP Call

- Final action was signed May 22, 2015, in response to a Sierra Club petition for rulemaking concerning SIP provisions for treatment of excess emissions occurring during periods of startup, shutdown and malfunction (SSM)
  - Final notice restates EPA's SSM Policy as it applies to SIPs with one change regarding affirmative defense (AD) provisions
- SIP Call applies to 36 states (45 jurisdictions), the majority of which were named in the original petition
- Challenge from multiple parties pending in D.C. Circuit Court

Draft Guidance on Significant Impact Levels (SILs) for Ozone and $PM_{2.5}$ in the Prevention of Significant Deterioration Permitting Program

- Draft guidance was posted August 18, 2016 and had a 60 day comment period through September 30, 2016
  - Draft guidance includes a memorandum that identifies recommended SIL values for ozone and $PM_{2.5}$ and describes how these values may be used in a PSD compliance demonstration;
  - A technical basis document (with supporting appendices) describing how EPA developed the SIL values for $PM_{2.5}$ and ozone; and
  - A legal support document that discusses a legal basis that permitting authorities may choose to apply if allowing sources to use SILs as part of their compliance demonstrations.
  - https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant
- Timing: TBD

Title V Permitting

- Title V Program and Fee Evaluation Guidance
  - Satisfies EPA commitments in response to a 2014 Office of Inspector General (OIG) report recommending enhanced oversight of state and local title V program fee revenue practices
    - * Committed to completing the revised guidance by Fall 2017
  - Provides guidance for EPA regions on conducting state and local title V program and fee evaluations
  - Discretionary for EPA regions and no specific requirements for state programs
  - Consistent with the principles and best practices for oversight of state permitting programs contained in the August 30, 2016 document *"Principles and Best Practices for Oversight of State Permitting Programs",* developed by EPA's Cross-Media State Programs Health and Integrity Workgroup

- Timing: TBD

Revisions to the Petition Provisions of the Title V Permitting Program

- Proposed rulemaking to increase transparency and stakeholder understanding of the petition process, as well as ensure that the Agency is able to efficiently address related programmatic and air quality issues was published on August 24, 2016 (81 FR 57822)

- The proposed revisions:
  - provide direction for submitting title V petitions, including encouraging the use of an electronic submittal system;
  - require mandatory content and format for title V petitions; and
  - require permitting authorities to respond in writing to significant comments received during the public comment period on draft title V permits.

- The preamble also provides guidance on "recommended practices" for permitting authorities and sources to help ensure title V permits have complete administrative records and are consistent with the CAA
  - If followed, these practices may reduce the likelihood that a petition will be submitted on a title V permit

- The comment period closed on October 24, 2016 and EPA is in the process of reviewing the comments received. Timing: TBD

Regulatory Updates for GHG Permitting

- EPA has taken a series of steps to respond to the June 23, 2014, Supreme Court decision in *Utility Air Regulatory Group (UARG) v. EPA* and the April 10, 2015, Court of Appeals for the District of Columbia (D.C. Circuit) *Coalition for Responsible Regulation v. EPA Amended Judgment*

  - In April 2015, EPA issued a final rulemaking revising EPA's PSD regulations to enable the EPA to rescind EPA-issued PSD permits for GHG
    - Direct Final (80 FR 26183); Parallel Proposal (80 FR 26210)

  - In August 2015, EPA issued a final **Prevention of Significant Deterioration and Title V Permitting for Greenhouse Gases: Removal of Certain Vacated Elements Rulemaking** (80 FR 50199)
    - Rule removed certain provisions from PSD and title V that were vacated as part of the D.C. Circuit Court's April 2015 Amended Judgment

  - On August 26, 2016, EPA proposed the **Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program** (81 FR 68110)
    - Rule also proposed the remaining changes to PSD and title V that are necessary to fully implement the D.C. Circuit Court's April 2015 amended judgment
    - The public comment period closed on December 16, 2016 and EPA is currently reviewing comments. Timing: TBD

Removal of Emergency Provisions from Part 70 and 71

- Proposed **Removal of Title V Emergency Affirmative Defense Provisions From State Operating Permit Programs and Federal Operating Permit Program Rule** to remove the "emergency" affirmative defense (AD) provisions from title V regulations 40 CFR 70.6(g) and 71.6(g) published on June 14m 2016 (81 FR 38645)

- The public comment period closed on August 15, 2016, and the EPA is currently evaluating all comments received

- This is a follow-up action to similar rulemakings, including the 2015 SSM SIP Call, intended to ensure that the EPA's policy on AD is consistent across all CAA program areas, following the D.C. Circuit's *2014 NRDC v. EPA* decision

- Timing: TBD

SIP Processing Improvements

- NACAA-ECOS-EPA SIP Reform Workgroup discussed need to reduce the SIP backlog and improve SIP processing

- Successful Implementation of Key Principles:
  - Set a goal of clearing the current backlog (as of October 1, 2013) by the end of 2017
  - Manage the review of all other SIPs consistent with Clean Air Act deadlines
  - Develop 4-year management plans agreed upon by EPA Regions and states that identify the highest priority SIPs to process and meet the backlog reduction goal
  - Use best practices and tools developed through the $PM_{2.5}$ Full Cycle Analysis Project (FCAP) to facilitate SIP processing
  - Increase transparency of SIP review status and improve EPA's SIP tracking system with fields that could be of assistance to states

SIP Processing Improvements (Con't)

- Trends in SIP Processing
  - EPA and air agencies are implementing the best practices from the $PM_{2.5}$ Full Cycle Analysis to improve SIP processing and assessing effectiveness to ensure continued improvement
  - 4-year management plans in place for each state
    - * Will continue to coordinate with states on multi-year SIP management plans as a standard practice
  - EPA and states making good progress on eliminating the SIPs backlogged as of October 1, 2013
    - * Backlogged SIPs reduced by 70%
  - EPA and states working together to prioritize SIPs and manage the review of all other SIPs consistent with Clean Air Act deadlines
    - * Active SIPs reduced by 32%

SIP Processing Improvements: Integrated Electronic System for SIP Submissions

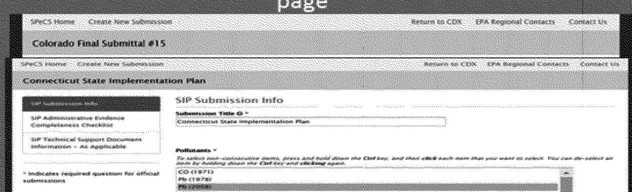
- Our vision is to create an integrated electronic submission system for SIPs and other state plans that enables us to:
  - Manage state submissions more efficiently and effectively
  - Increase transparency through data availability

- EPA embarking on project to leverage new Agency IT systems to improve and modernize the SIP submission process by allowing for:
  1) Developing and transmitting SIP submissions;
  2) Internal EPA review, collaboration, tracking and storage of plans;
  3) External public interface that provides status information on EPA action on SIPs, links to submittals, and links to FR notices; and
  4) Additional functionality, such as maintaining SIP compilations and accommodating other types

Vision: SPeCS for SIPs: Major Components

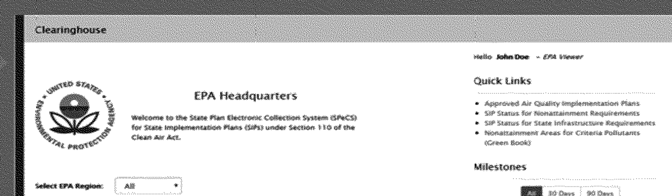
State Plan Collection Interface

Compilation and submission of plans using checklists, file upload capability, completeness checks and a state landing page



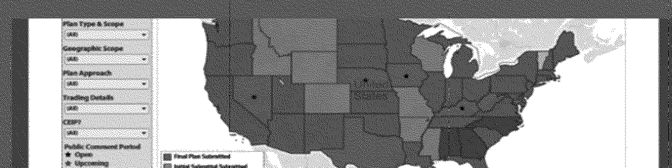
EPA Plan Review Clearinghouse

SIP requirement tracking, Issue tracking, storage of submittals and compliance with SIP requirements



Public Dashboard

Plan status updates, links to final approved plans, national and individual state SIP information



Questions and Comments

To: Wood, Anna[Wood.Anna@epa.gov]
Cc: Anna Marie Wood[anna.wood@usa.net]
From: Anna Marie Wood
Sent: Mon 9/18/2017 3:46:18 AM
Subject: AAPCA slide deck
NACAA 2017 Fall Full Deck w_TPs.pptx

Anna Marie Wood
E-Mail- Anna.Wood@usa.net

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Tue 10/24/2017 7:21:26 PM
Subject: Draft SESARM 2017 presentation
SESARM 2017 Fall _wTPs_oct 24.pptx

Attached is the draft SESARM presentation which incorporates the updated slides Vera provided. I talked with Lynorae today and she said that her states are not really interested in 2008 ozone or PM since they are in attainment so I have moved all of that to the appendix. She gave me the list of what the states wanted and you have touched on all: permit streamlining, SSM, transport, ozone 2015, SO2, RH, and EE. She will be doing a session right after you which focuses on the attainment and maintenance of NAAQS and the SIP backlog specific to the R4 states.

Please let me know what you think. Lynorae would like a copy of the slides whenever you are finished so that she make sure she does not duplicate anything.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Johnson, Yvonne W[Johnson.Yvonnew@epa.gov]
Cc: Wood, Anna[Wood.Anna@epa.gov]
From: Rao, Raj
Sent: Tue 6/20/2017 4:16:48 PM
Subject: FW: BP America would like to meet on regulatory reform proposals related to the NSR Program

Yvonne, 27th am works for me. If it also works for Anna and others, then you could schedule that time. Also, please invite Dave, Peter and Jessica as well – but do not schedule around them – thanks

raj

Raj Rao, P.E.
Group Leader, New Source Review Group,
Air Quality Policy Division,
Office of Air Quality Planning and Standards (MD-C504-03)
US Environmental Protection Agency
109 TW Alexander Drive
Research Triangle Park, NC 27709
919-541-5344
919-541-5509 - Fax

From: van Hoogstraten, David Jan [mailto:David.vanHoog@bp.com]
Sent: Tuesday, June 20, 2017 11:46 AM
To: Rao, Raj <Rao.Raj@epa.gov>
Cc: Nolan, James <James.Nolan@bp.com>; Svendsgaard, Dave <Svendsgaard.Dave@epa.gov>; Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>
Subject: RE: BP America would like to meet on regulatory reform proposals related to the NSR Program

Raj:

If it would be possible to see you all on Tuesday, June 27, that would be most convenient for us. The 26th would work and, if need be, I think we could come on July 6. We would be most appreciative if you could let us know as soon as possible what would work at your end.

Many thanks and regards,

David

David J. van Hoogstraten

Senior Director, Regulatory Affairs (Environmental)

BP America Inc.

1101 New York Avenue, NW

Washington, DC 20005

Direct: 202 457 6596

Mobile: 202 277 5840

From: Rao, Raj [mailto:Rao.Raj@epa.gov]
Sent: Monday, June 19, 2017 2:23 PM
To: van Hoogstraten, David Jan
Cc: Nolan, James; Svendsgaard, Dave; Johnson, Yvonne W
Subject: RE: BP America would like to meet on regulatory reform proposals related to the NSR Program

Thanks David – let me check in with my folks and get back to you. I am hopeful that we should be able to work something out for those days. Yvonne will coordinate with you.

Raj

Raj Rao, P.E.
Group Leader, New Source Review Group,
Air Quality Policy Division,
Office of Air Quality Planning and Standards (MD-C504-03)
US Environmental Protection Agency

109 TW Alexander Drive
Research Triangle Park, NC 27709
919-541-5344
919-541-5509 - Fax

Note: Positions or views expressed here do not represent official EPA policy.
Interagency Deliberative and Confidential

From: van Hoogstraten, David Jan [mailto:David.vanHoog@bp.com]
Sent: Monday, June 19, 2017 1:27 PM
To: Rao, Raj <Rao.Raj@epa.gov>
Cc: Nolan, James <James.Nolan@bp.com>; Svendsgaard, Dave <Svendsgaard.Dave@epa.gov>
Subject: RE: BP America would like to meet on regulatory reform proposals related to the NSR Program

Raj:

I have recently heard back from Peter Tsirigotis with whom we also hope to have a general discussion around opportunities for regulatory reform. His office has provided us with several times and dates (June 26 from 2-4; June 27 from 1-3; July 5 from 10-11:30 and July 6 between 1 and 5). Our hope would be to meet with whomever you would assemble on the NSR issues on the same day we come down to see Peter. If possible, we would like to go down and back on the same day. Please let us know what might work.

Many thanks and best regards,

David

David J. van Hoogstraten

Senior Director, Regulatory Affairs (Environmental)

BP America Inc.

1101 New York Avenue, NW

Washington, DC 20005

Direct: 202 457 6596

Mobile: 202 277 5840

From: Rao, Raj [mailto:Rao.Raj@epa.gov]
Sent: Thursday, June 15, 2017 3:37 PM
To: van Hoogstraten, David Jan
Cc: Nolan, James; Svendsgaard, Dave
Subject: Re: BP America would like to meet on regulatory reform proposals related to the NSR Program

David, thanks for your email requesting a meeting with us to talk about your NSR reform ideas. I am on travel this week. Next week, I will check in with my management and get back with you soon. We appreciate all input in streamlining the NSR program

Thanks for reaching out to us.

Raj

Sent from my iPhone

On Jun 15, 2017, at 12:46 PM, van Hoogstraten, David Jan <David.vanHoog@bp.com> wrote:

> Dear Mr. Rao:
>
> At some point during the next two weeks, BP America would greatly appreciate the opportunity to come in to your office to meet with you and whomever you think appropriate about "regulatory reform" ideas we have that would involve certain changes in the NSR permitting program. This is in connection with the Executive Order entitled "Promoting Energy Independence and Economic Growth" ("E.O") signed by the President on March 28, 2017.
>
> Once we have discussed our thoughts with you and formulated them more fully, we would, after further consultation with EPA, make proposals formally to the Agency with the hope

that it would pass them on to OMB/OIRA. Under the E.O., Agencies have until July 26 to submit draft energy independence reform plans to OMB and the Vice President.

This morning I had a brief conversation with your colleague, Vera Komylak, during which I explained some of this and expressed our interest in coming to research Triangle Park to have a discussion. I would propose to come down together with one of our internal NSR subject matter experts and an outside consultant. Please let me know if you would like any additional information from us.

Please let us know whether it would be possible to get together with you in person sometime during the next couple of weeks.

Many thanks and best regards,

David J. van Hoogstraten

Senior Director, Regulatory Affairs (Environmental)

BP America Inc.

1101 New York Avenue, NW

Washington, DC 20005

Direct: 202 457 6596

Mobile: 202 277 5840

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Fri 3/24/2017 5:43:57 PM
Subject: revised NAAQS slides with TPs
2017 AAPCA Slides_NAAQS_TPs_Final.pptx

Here are the revised slides with the removal of the one sub-bullet under slide 17 and the removal of 2 specs slides. I added tps from the first specs slide to the one he wanted me to keep. Click there and you will see that I mean.

Please double check to make sure that the slides I printed match these. I don't like not being able to do that myself.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

NAAQS AND OTHER IMPLEMENTATION UPDATES

Anna Marie Wood, Director
Air Quality Policy Division
OAQPS, U.S. EPA
AAPCA Spring Meeting
March 2017

OVERVIEW

- NAAQS Implementation Updates
  - Ozone
  - Sulfur Dioxide (SO_2)
  - Fine Particulate Matter ($PM_{2.5}$)
- Startup, Shutdown, and Malfunction (SSM) Policy for SIPs and SIP Call
- NSR and Title V Permitting Updates
- Reducing the SIP Backlog
- State Plan Electronic Collections System for SIPs

NAAQS Reviews: Status Update

(March 2017)

	Ozone	Lead	Primary NO_2	Primary SO_2	Secondary (Ecological) NO_2, SO_2, PM[1]	PM[2]	CO
Last Review Completed (final rule signed)	Oct. 2015	Sept 2016	Jan 2010	Jun 2010	Mar 2012	Dec 2012	Aug 2011
Recent or Upcoming Major Milestone(s)[3]	TBD[4]	TBD[4]	Jan 2016 Final ISA Sep 2016 1st Draft PA Spring 2017 Final PA	Dec 2016 2nd Draft ISA Feb 2017 REA Planning Document March 2017 CASAC review of Draft ISA and REA Planning Document	Jan 2017 Final IRP Spring 2017 CASAC review of 1st Draft ISA	Dec 2016 Final IRP Winter 2017/2018 1st draft ISA REA Planning Document	TBD[4]

Additional information regarding current and previous NAAQS reviews is available at:
http://www.epa.gov/ttn/naaqs/

[1] Combined secondary (ecological effects only) review of NO_2, SO_2, and PM
[2] Combined primary and secondary (non-ecological effects) review of PM
[3] IRP – Integrated Review Plan; ISA – Integrated Science Assessment; REA – Risk and Exposure Assessment; PA – Policy Assessment
[4] TBD = to be determined

Anticipated NAAQS Implementation Milestones

(March 2017)

Pollutant	Final NAAQS Date	Designations Effective	Infrastructure SIP Due	Attainment Plans Due	Attainment Date
$PM_{2.5}$ (2006)	Oct 2006	Dec 2009	Oct 2009	Dec 2014	Dec 2015 (Mod) Dec 2019 (Ser)
Pb (2008)	Oct 2008	Dec 2010-2011	Oct 2011	June 2012-2013	Dec 2015-2019
$PM_{2.5}$ (2012)	Dec 2012	Apr 2015	Dec 2015	Oct 2016 (Mod)	Dec 2021 (Mod) Dec 2025 (Ser)
NO_2 (2010) (primary)	Jan 2010	Feb 2012	Jan 2013	N/A	N/A
SO_2 (2010) (primary)	June 2010	Oct 2013, Sept 2016 (+2 rounds)	June 2013	April 2015, March 2018 (2019, 2022)	Oct 2018, Sept 2021 (2023, 2026)
Ozone (2008)	Mar 2008	July 2012	Mar 2011	Mid 2015-2016	Mid 2015-2032
Ozone (2015)	Oct 2015	Dec 2017	Oct 2018	Dec 2020-2021	2020-2037

2008 Ozone NAAQS Implementation

- **Final Implementation of the 2008 NAAQS for Ozone: State Implementation Plan Requirements Rule** published March 6, 2015 (80 FR 12264)
  - Provides interpretive rules and guidance on nearly all aspects of the attainment planning requirements for designated nonattainment areas
  - Revoked the 1997 NAAQS (effective April 6, 2015) and established anti-backsliding requirements

- Key implementation dates for nonattainment areas:
  - Emissions inventories, emissions statement rules and RACT SIPs due July 2014
  - Attainment plans and demonstrations due July 2015 (Moderate) or July 2016 (Serious and above)
  - Marginal area attainment date July 20, 2015 (attainment determined by 2012-2014 air quality data)
  - Moderate area attainment date July 20, 2018 (2015-2017 air quality data)

2008 Ozone NAAQS Implementation: Litigation

- South Coast Air Quality Management District and environmental petitioners (Sierra Club *et al.*) challenged various aspects of the 2008 Ozone NAAQS SIP Requirements Rule, including creditability of reasonable further progress (RFP) control measures, revocation of 1997 NAAQS and application of regulatory anti-backsliding requirements (final briefs submitted; oral arguments schedule TBD)

- In response to a complaint filed by environmental petitioners, the EPA found that 15 states and the District of Columbia failed to submit certain SIP revisions required under the 2008 ozone NAAQS (82 FR 9158; February 3, 2017).
  - The finding of failure to submit action gives formal notice to affected parties, and establishes deadlines by which they either must submit complete SIP revisions or become subject to mandatory sanctions.
  - Petitioners further alleged that EPA failed to take final action on SIP submittals by various states under the 1997 and 2008 ozone NAAQS.
  - EPA entered into a Consent Decree with the petitioners on January 19, 2017, which sets deadlines for EPA to complete final actions on SIP submittals by various dates ranging from June 2017 to July 2018.

Progress on Ozone NAAQS Attainment

(as of March 2017)

	1997 NAAQS (2004 Designations)	2008 NAAQS (2012 Designations)
Initial Nonattainment Areas	115	46
Areas Redesignated to Attainment	80 (prior to revocation)	6
Current Nonattainment Areas	35	40
Clean Data Determinations	26	18*
Redesignation Substitutes	2	0
Reclassifications to Higher Classification	N/A after revocation	13

*Includes 15 Marginal area determinations of attainment by the attainment date and 3 Moderate area clean data determinations.

2015 Ozone NAAQS: Implementation-Related Rules/Guidance/Activities

- **Final National Ambient Air Quality Standards for Ozone Rule** signed October 1, 2015 (40 FR 65292), revising the primary and secondary 8-hour ozone standards to 0.070 ppm
  - Litigation pending on the level of the standard (oral arguments scheduled for April 19, 2017)
- **Proposed Rule: Implementation of the 2015 NAAQS for Ozone: Nonattainment Area Classifications and State Implementation Plan Requirements** published November 17, 2016 (81 FR 81276)
  - Can be found at https://www.epa.gov/ozone-pollution/implementation-2015-national-ambient-air-quality-standards-naaqs-ozone-state
  - Proposed rule comment period closed February 13, 2017; timing of final rule TBD
- PSD permitting tools/guidance:
  - Final update to Guideline on Air Quality Models (Appendix W to 40 CFR Part 51)
  - Guidance on compliance demonstration tools:
    - Ozone and $PM_{2.5}$ significant impact levels (SILs) (posted for comment in August 2016)
    - Model emissions rates for precursors (MERPs)
- Update to transportation conformity guidance specific to nonattainment areas for 2015 NAAQS (Fall 2017)

2015 Ozone NAAQS Implementation Rule Proposal: Key Topics

- Nonattainment area classification thresholds
  - Proposed the current "percent-above-the-standard" classification thresholds method. Moderate=81ppb
- Revocation of the 2008 Ozone NAAQS - 2 options
  - Opt 1: revoke the 2008 NAAQS for all areas and purposes 1 year after designations are effective (historical ozone approach)
  - Opt 2: revoke the 2008 NAAQS only in areas attaining the 2008 NAAQS at time of its revocation, and later for areas upon redesignation to attainment for the 2008 or 2015 NAAQS (similar to $PM_{2.5}$ approach)
- Submitting nonattainment area and OTR SIP elements
  - Clear listing of required SIP elements
  - How to submit "certification" SIPs

2015 Ozone NAAQS: Anticipated Timeline for Designations Process

Milestone	Date
The EPA promulgates 2015 Ozone NAAQS rule	October 1, 2015
The EPA issues designations guidance	February 25, 2016
Air agencies submit exceptional events demonstrations for data years 2014-2015	No later than the date recommendations are due to EPA (October 1, 2016)
States and tribes submit recommendations for ozone designations (and exceptional events demonstrations for data years 2014-2015) to EPA	No later than October 1, 2016
The EPA notifies states and tribes concerning any intended modifications to their recommendations (120-day letters)	No later than June 2, 2017 (120 days prior to final ozone area designations)
The EPA publishes public notice of state and tribal recommendations and the EPA's intended modifications, if any, and initiates 30-day public comment period	On or about June 9, 2017
End of 30-day public comment period	On or about July 10, 2017
States and tribes submit additional information, if any, to respond to the EPA's modification of a recommended designation	No later than August 7, 2017
The EPA promulgates final ozone area designations	No later than October 1, 2017

2010 SO_2 NAAQS Implementation

- EPA revised **Primary NAAQS for Sulfur Dioxide (SO_2) standard** on June 3, 2010 to 75 ppb/1-hour (75 FR 35520)

- EPA designated 29 areas as nonattainment on July 25, 2013 (Round 1)
  - **Guidance for 1-hr SO_2 NAAQS NAA SIP Submissions** was issued on April 23, 2014
  - Attainment plans for the 29 areas were due April 4, 2015
  - EPA issued findings of failure (FFS) to submit attainment plans for 16 areas in 11 states, effective April 18, 2016 (81 FR 14736; published March 18, 2016)

- EPA is required to promulgate a Federal Implementation Plan (FIP) if a state does not submit, and EPA does not approve the required SIPs within 24 months of the effective date of the FFS (i.e., April 18, 2018)

- EPA is working with affected states to develop SIPs

2010 SO_2 NAAQS Designations

- Consent decree entered on March 2, 2015, by U.S. District Court for Northern California in *SIERRA CLUB and NATURAL RESOURCES DEFENSE COUNCIL v. EPA* "triggered" the following deadlines:
  - July 2, 2016 - The EPA must complete a round of designations for 61 areas associated with approximately 64 EGUs in 24 states and any undesignated areas with violating monitors ("Round 2" designations)
  - December 31, 2017 - The EPA must complete an additional round of designations for any area a state has not established a new monitoring network by January 1, 2017 per the provisions of the SO_2 Data Requirements Rule
  - December 31, 2020 - The EPA must complete designations of all remaining, undesignated areas (expected to be areas where states elected to monitor per the provisions of the DRR)

2010 SO_2 Designations Due on July 2, 2016 Under Consent Decree

- On June 30, 2016, EPA finalized designations for 61 areas for "Round 2":
  - Areas where there are sources (electric power plants) that as of March 2, 2015, have not been "announced for retirement," and
  - Areas that meet one of the following emissions thresholds:
    - 16,000 tons of emitted in 2012 or
    - 2,600 tons of SO_2 emitted in 2012 with an average emission rate of at least 0.45 pounds of SO_2 per mmBtu
  - Areas where 2013-15 data indicate monitored violations – only Hawaii County, HI – which was determined to be an Exceptional Event

- These designations included 4 nonattainment areas, 41 unclassifiable/attainment areas, and 16 unclassifiable areas

SO_2 NAAQS Data Requirements Rule: Milestones

- **January 15, 2016:** Deadline for air agency to identify applicable sources (i.e., those exceeding threshold and other sources for which air quality will be characterized)
  - EPA notified states in March 2016 that review of source lists was complete. In a few cases, EPA added sources to characterization list
- **July 1, 2016:** Deadline for air agency to specify (for each applicable source) whether it will monitor air quality, model air quality, or establish an enforceable limit
  - Air agency also accordingly submits a revised monitoring plan, modeling protocols, or descriptions of planned limits on source emissions to less than 2,000 tpy, or documentation that a source has shut down
- **January 2017**
  - January 1: Deadline for new monitoring sites to be operational
  - January 13: Deadline for air agency to submit modeling analyses or documentation of emission limits/shut down
- **Early 2020:** Monitoring sites will have 3 years of quality-assured data which must be submitted to EPA

- EPA's website has recently been updated with state submittals associated with these milestones and related correspondence with EPA
  - https://www.epa.gov/so2-pollution/final-data-requirements-rule-2010-1-hour-sulfur-dioxide-so2-primary-national-ambient

Intended Schedule for Area Designations for 2010 SO_2 NAAQS Due on December 31, 2017 (Round 3)

Milestone	Date
States and tribes may submit updated recommendations and supporting information for area designations to the EPA	No later than January 13, 2017
States and tribes submit modeling analyses pursuant to SO2 Data Requirements Rule	No later than January 13, 2017
States submit exceptional events demonstrations for event-influenced SO2 monitoring data from 2015-2016	No later than July 14 , 2017
The EPA notifies states and tribes concerning any intended modifications to their recommendations (120-day letters)	on/about August 14, 2017 (no later than 120 days prior to final designations)
The EPA publishes public notice of state and tribal recommendations and the EPA's intended modifications and initiates 30-day public comment period	on/about August 24, 2017
End of 30-day public comment period	on/about September 24, 2017
States and tribes submit additional information, if desired, to demonstrate why an EPA modification is inappropriate	No later than October 13, 2017
The EPA signs notice promulgating final SO2 area designations for Round 3	on/about December 14, 2017 (can be no later than December 31, 2017)

$PM_{2.5}$ NAAQS Implementation: SIP Requirements Rule

- **$PM_{2.5}$ NAAQS SIP Requirements Rule** finalized on August 24, 2016 (81 FR 58010) provided framework for planning requirements for 2012 and future $PM_{2.5}$ NAAQS and informs implementation for areas still violating 1997 and/or 2006 $PM_{2.5}$ NAAQS

- November 2016 EPA issued draft **$PM_{2.5}$ Precursor Demonstration Guidance**
  - Recommends technical approaches for precursor demonstrations to assess whether air quality impact from a particular precursor can be considered to be insignificant in a given area
  - Comment period extended to March 31, 2017

- South Coast Air Quality Management District filed suit challenging two aspects of the rule:
  1. Requirement that emissions reductions for RFP come from sources within the nonattainment area (consistent with past court decision)
  2. Lack of explicit "de minimis" source category exclusion for Reasonably Available Control Measures (RACM) and Best Available Control Measures (BACM)
  - Petitioner's brief due on April 4, 2017; EPA response brief due June 6, 2017

2006 $PM_{2.5}$ NAAQS Implementation

- In December 2016, EPA proposed:
  - Determinations of attainment for 7 areas
  - Findings of failure to attain by the December 31, 2015 attainment date, and reclassification to Serious for 4 areas
  - The action is a mandatory requirement under the CAA and will fulfill obligations included in consent decrees resulting from two lawsuits.

- Serious area attainment date is December 31, 2019
  - Extension up to December 31, 2024 is possible if cannot demonstrate attainment by 2019. Requires Most Stringent Measures in any state.

- EPA plans to take final action this year on a number of submitted Moderate area plans and will continue to work with states developing Serious area plans to address air quality challenges.

2012 $PM_{2.5}$ NAAQS Implementation

- December 14, 2012 revised the $PM_{2.5}$ NAAQS primary annual $PM_{2.5}$ standard to 12µg/m^3 (78 FR 3086)
  - Nine Moderate nonattainment areas were designated in 2015
  - Moderate area attainment plan due date - October 2016
  - Moderate area attainment date - December 31, 2021
  - Serious area attainment date - December 31, 2025

Progress on $PM_{2.5}$ NAAQS Attainment

(as of March 2017)

	1997 $PM_{2.5}$ (2005 Designations)	2006 $PM_{2.5}$ (2009 Designations)	2012 $PM_{2.5}$ (2015 Designations)
Initial Nonattainment Areas	39	32	9
Areas Redesignated to Attainment	31	16	0
Current Nonattainment Areas	8	16	9
Clean Data Determinations	5	8	1
Proposed Redesignations	0	0	0

Response to SSM Petition, Final Policy and SIP Call

- Final action was signed May 22, 2015, in response to a Sierra Club petition for rulemaking concerning SIP provisions for treatment of excess emissions occurring during periods of startup, shutdown and malfunction (SSM)
  - Final notice restates EPA's SSM Policy as it applies to SIPs with one change regarding affirmative defense (AD) provisions
- SIP Call applies to 36 states (45 jurisdictions), the majority of which were named in the original petition
- Challenge from multiple parties pending in D.C. Circuit Court

Draft Guidance on Significant Impact Levels (SILs) for Ozone and $PM_{2.5}$ in the Prevention of Significant Deterioration Permitting Program

- Draft guidance was posted August 18, 2016 and had a 60 day comment period through September 30, 2016
  - Draft guidance includes a memorandum that identifies recommended SIL values for ozone and $PM_{2.5}$ and describes how these values may be used in a PSD compliance demonstration;
  - A technical basis document (with supporting appendices) describing how EPA developed the SIL values for $PM_{2.5}$ and ozone; and
  - A legal support document that discusses a legal basis that permitting authorities may choose to apply if allowing sources to use SILs as part of their compliance demonstrations.
  - https://www.epa.gov/nsr/draft-guidance-comment-significant-impact-levels-ozone-and-fine-particle-prevention-significant
- Timing: TBD

Title V Permitting

- Title V Program and Fee Evaluation Guidance
  - Satisfies EPA commitments in response to a 2014 Office of Inspector General (OIG) report recommending enhanced oversight of state and local title V program fee revenue practices
    - Committed to completing the revised guidance by Fall 2017
  - Provides guidance for EPA regions on conducting state and local title V program and fee evaluations
  - Discretionary for EPA regions and no specific requirements for state programs
  - Consistent with the principles and best practices for oversight of state permitting programs contained in the August 30, 2016 document *"Principles and Best Practices for Oversight of State Permitting Programs"*, developed by EPA's Cross-Media State Programs Health and Integrity Workgroup

- Timing: TBD

Principles and Best Practices for Oversight of State Permitting Program

- The EPA's Cross-Media State Programs Health and Integrity Workgroup was created in response to an OIG Report from 2011
- The workgroup developed the principles intended to be used to guide future oversight activities in three major permitting programs: the Clean Water Act National Pollutant Discharge Elimination System Program, the Clean Air Act Title V program, and the Resource Conservation and Recovery Act subtitle C program.
- The principles and best practices were developed by EPA in consultation with ECOS, the Association of Clean Water Administrators, NACAA, AAPCA, and the Association of State and Territorial Solid Waste Management Officials.
- Established common principles and best practices to promote efficient and effective oversight of state, local, and tribal permitting programs for air, water, and solid waste.

Revisions to the Petition Provisions of the Title V Permitting Program

- Proposed rulemaking to increase transparency and stakeholder understanding of the petition process, as well as ensure that the Agency is able to efficiently address related programmatic and air quality issues was published on August 24, 2016 (81 FR 57822)
- The proposed revisions:
  - provide direction for submitting title V petitions, including encouraging the use of an electronic submittal system;
  - require mandatory content and format for title V petitions; and
  - require permitting authorities to respond in writing to significant comments received during the public comment period on draft title V permits.
- The preamble also provides guidance on "recommended practices" for permitting authorities and sources to help ensure title V permits have complete administrative records and are consistent with the CAA
  - If followed, these practices may reduce the likelihood that a petition will be submitted on a title V permit
- The comment period closed on October 24, 2016 and EPA is in the process of reviewing the comments received. Timing: TBD

Regulatory Updates for GHG Permitting

- EPA has taken a series of steps to respond to the June 23, 2014, Supreme Court decision in *Utility Air Regulatory Group (UARG) v. EPA* and the April 10, 2015, Court of Appeals for the District of Columbia (D.C. Circuit) *Coalition for Responsible Regulation v. EPA Amended Judgment*

  - In April 2015, EPA issued a final rulemaking revising EPA's PSD regulations to enable the EPA to rescind EPA-issued PSD permits for GHG
    - Direct Final (80 FR 26183); Parallel Proposal (80 FR 26210)

  - In August 2015, EPA issued a final **Prevention of Significant Deterioration and Title V Permitting for Greenhouse Gases: Removal of Certain Vacated Elements Rulemaking** (80 FR 50199)
    - Rule removed certain provisions from PSD and title V that were vacated as part of the D.C. Circuit Court's April 2015 Amended Judgment

  - On August 26, 2016, EPA proposed the **Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program** (81 FR 68110)
    - Rule also proposed the remaining changes to PSD and title V that are necessary to fully implement the D.C. Circuit Court's April 2015 amended judgment
    - The public comment period closed on December 16, 2016 and EPA is currently reviewing comments. Timing: TBD

Removal of Emergency Provisions from Part 70 and 71

- Proposed **Removal of Title V Emergency Affirmative Defense Provisions From State Operating Permit Programs and Federal Operating Permit Program Rule** to remove the "emergency" affirmative defense (AD) provisions from title V regulations 40 CFR 70.6(g) and 71.6(g) published on June 14m 2016 (81 FR 38645)

- The public comment period closed on August 15, 2016, and the EPA is currently evaluating all comments received

- This is a follow-up action to similar rulemakings, including the 2015 SSM SIP Call, intended to ensure that the EPA's policy on AD is consistent across all CAA program areas, following the D.C. Circuit's *2014 NRDC v. EPA* decision

- Timing: TBD

SIP Processing Improvements

- NACAA-ECOS-EPA SIP Reform Workgroup discussed need to reduce the SIP backlog and improve SIP processing

- Successful Implementation of Key Principles:
  - Set a goal of clearing the current backlog (as of October 1, 2013) by the end of 2017
  - Manage the review of all other SIPs consistent with Clean Air Act deadlines
  - Develop 4-year management plans agreed upon by EPA Regions and states that identify the highest priority SIPs to process and meet the backlog reduction goal
  - Use best practices and tools developed through the $PM_{2.5}$ Full Cycle Analysis Project (FCAP) to facilitate SIP processing
  - Increase transparency of SIP review status and improve EPA's SIP tracking system with fields that could be of assistance to states

SIP Processing Improvements (Con't)

- Trends in SIP Processing
  - EPA and air agencies are implementing the best practices from the $PM_{2.5}$ Full Cycle Analysis to improve SIP processing and assessing effectiveness to ensure continued improvement
  - 4-year management plans in place for each state
    - Will continue to coordinate with states on multi-year SIP management plans as a standard practice
  - EPA and states making good progress on eliminating the SIPs backlogged as of October 1, 2013
    - Backlogged SIPs reduced by 70%
  - EPA and states working together to prioritize SIPs and manage the review of all other SIPs consistent with Clean Air Act deadlines
    - Active SIPs reduced by 32%

SIP Processing Improvements: Integrated Electronic System for SIP Submissions

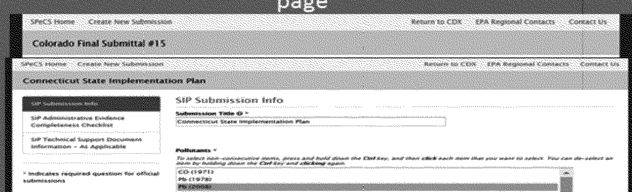
- Our vision is to create an integrated electronic submission system for SIPs and other state plans that enables us to:
  - Manage state submissions more efficiently and effectively
  - Increase transparency through data availability

- EPA embarking on project to leverage new Agency IT systems to improve and modernize the SIP submission process by allowing for:
  1) Developing and transmitting SIP submissions;
  2) Internal EPA review, collaboration, tracking and storage of plans;
  3) External public interface that provides status information on EPA action on SIPs, links to submittals, and links to FR notices; and
  4) Additional functionality, such as maintaining SIP compilations and accommodating other types

Vision: SPeCS for SIPs: Major Components

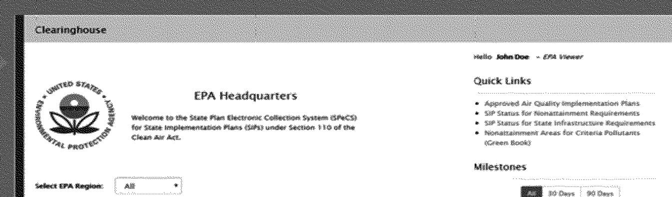
State Plan Collection Interface

Compilation and submission of plans using checklists, file upload capability, completeness checks and a state landing page



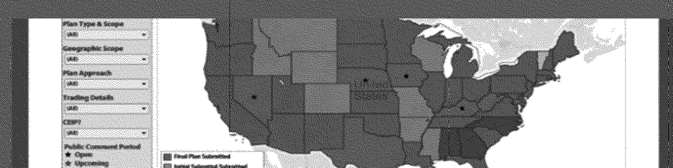
EPA Plan Review Clearinghouse

SIP requirement tracking, Issue tracking, storage of submittals and compliance with SIP requirements



Public Dashboard

Plan status updates, links to final approved plans, national and individual state SIP information



Questions and Comments

APPENDIX

Intended Schedule for 2015 Ozone NAAQS Implementation Rules/Guidance/Tools

Action	After NAAQS Promulgation	(Actual) and Planned Dates
EPA proposes nonattainment area SIP rules/guidance (including area classifications thresholds, SIP due dates, and nonattainment NSR provisions)	12 months	(November 2016)
EPA finalizes designations, classifications, and nonattainment area SIP rules/guidance	24 months	October 2017
States submit infrastructure and transport SIPs	36 months	October 2018
States submit attainment plans	5-6 years	2020-2021
Nonattainment area attainment dates (Marginal – Extreme)	5-22 years	2020-2037

To: Wood, Anna[Wood.Anna@epa.gov]; Johnson, Yvonne W[Johnson.Yvonnew@epa.gov]
From: Long, Pam
Sent: Fri 9/15/2017 1:39:41 PM
Subject: File for presentation from Sharepoint
NACAA 2017 Fall Full Deck w_TPs.pptx

I pulled this from Sharepoint. Do you want me to print it also with TPs?

From: Wood, Anna
Sent: Friday, September 15, 2017 9:33 AM
To: Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>
Cc: Long, Pam <Long.Pam@epa.gov>
Subject: RE: presentation

I think Rhea is done for now—I have a 1 on 1 with her at 930 this morning and will confirm that. Please go ahead and download it for me as I plan to work on these this morning—thank you both.

Also I spoke to Idalia and told her I would get her the revised ADD agenda this morning—Yvonne I will look at the email you sent about adding something to the agenda. thx

From: Johnson, Yvonne W
Sent: Thursday, September 14, 2017 10:05 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Cc: Long, Pam <Long.Pam@epa.gov>
Subject: presentation

I will call you tomorrow morning. I can see where Megan and Rhea have been making edits to the presentation. Megan sent an email saying she has completed. Not completely sure about Rhea. The file is still on the sharepoint site so when you are ready either Pam or I can download it and send it to you.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Wed 10/4/2017 8:12:08 PM
Subject: censara 2017 Fall presentation (draft) and ADD ozone slides
censara 2017 Fall _wTPs_oct 4.pptx
2017 Fall ADD O3 Implementation_TPs_FINAL.pptx

Attached is an electronic version of the censara slides (hardcopy in your chair). You also mentioned wanting to look at ADD ozone slides so they are included here and in your chair as well.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Thur 9/14/2017 1:48:02 AM
Subject: here is the latest but....NACAA 2017 Fall Full Deck w_TPs.pptx
NACAA 2017 Fall Full Deck w_TPs.pptx

Here is the latest version of slides but…

•□□□□□□□□ Rhea said she still needs to work on slides 17, 20, and 22

•□□□□□□□□ Megan needs to work on slides 33-36

•□□□□□□□□ As I look at this version I have several questions and then there are comments it looks like I need to work through.

I am on leave Thurs. (at least for the morning). I may be able to work some in the afternoon and I can work on Friday. I will touch base with you tomorrow. They need more work. They are just not ready.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Anna Marie Wood
Sent: Mon 10/30/2017 12:51:43 AM
Subject: SESARM Slides
SESARM 2017 Fall _wTPs_oct 29+Final EO Slides (1).pptx

Anna Marie Wood
E-Mail- Anna.Wood@usa.net

NAAQS AND OTHER IMPLEMENTATION UPDATES

Anna Marie Wood, Director
Air Quality Policy Division
OAQPS, U.S. EPA
SESARM Fall Meeting
November 1, 2017

Overview

- Update on Executive Orders and Actions
- NAAQS Implementation Updates
  - 2015 Ozone
  - 2010 SO_2
- Exceptional Events
- Transport
- Regional Haze
- Startup, Shutdown, and Malfunction (SSM) Policy for SIPs and SIP Call
- NSR and Title V Permitting Updates
- Reducing the SIP Backlog
- State Plan Electronic Collections System (SPeCS) for SIPs

Permit Streamlining Executive Actions

- Review of directly applicable Presidential Actions
  - Pres. Mem. on Permit Streamlining
  - EO 13783 (Promoting Energy Independence and Economic Growth)
  - EO 13771 (Reducing Regulatory and Controlling Regulatory Costs)
  - EO 13776 (Expediting Environmental Reviews and Approvals for High Priority Infrastructure Projects)
  - EO 13777 (Enforcing the Regulatory Reform Agenda)
  - Directive Promoting Transparency and Public Participation in Consent Decrees and Settlement Agreements

Presidential Memorandum on Permit Streamlining

- Signed on January 24, 2017, this presidential memorandum is titled, "Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing."
- Department of Commerce was in the lead and provided an opportunity for public comment on ways to achieve the goals of the memorandum. The comment period closed on March 31, 2017. Approximately 170 commenters submitted comments.
- The majority of air related comments submitted involve issues of NSR permitting, with some also discussing title V, NESHAPs, and NSPS.
- With regard to air permitting, comments largely focused on NSR and within NSR, NSR applicability was an area where there were a lot of comments.
- Final Report issued Oct. 6, 2017. Available online at:

https://www.commerce.gov/sites/commerce.gov/files/streamlining_permitting_and_reducing_regulatory_burdens_for_domestic_manufacturing.pdf

Report: Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing

- **Three major recommendations**
  - Each agency's regulatory reform task force should deliver to the President an "Action Plan" in response to all permitting and regulatory issues highlighted, with particular attention to the "Priority Areas for Reform."
  - Each agency establish an annual, open forum for regulators and industry stakeholders to evaluate progress in reducing regulatory burdens.
  - Use existing authority to extend the use of the streamlined permitting procedures used in "FAST-41" for any project that will result in a significant, immediate economic benefit to the United States.

- **Upcoming activities/dates**
  - Action Plans due by Dec. 31, 2017.

- **Permitting-Specific Recommendations**
  - 11 total recommendations involving NSR and title V permitting.
  - NSR recommendations regarding issues such as consider options to revise the definition of routine maintenance, repair and replacement; project netting; aggregation; and changes to offset requirements, among others.
  - One title V recommendation involved extending the term of the permit from 5 to 10 years.
  - The report also identifies other program areas such as NESHAPs, NSPS, and others for reform.

Executive Order 13783: Promoting Energy Independence and Economic Growth

- Signed on March 28, 2017
  - Rescinds EO 13653 (Preparing the U.S. for the Impacts of Climate Change), Pres. Memo of June 25, 2013 (Power Sector Carbon Pollution Standards), Pres. Memo of November 3, 2015 (Mitigating Impacts of Natural Resources from Development and Encouraging Related Private Investment), Pres. Memo of September 21, 2016 (Climate Change and National Security), "President's Climate Action Plan" (June 2013), and "Climate Action Plan Strategy to Reduce Methane Emissions" (March 2014).
  - Review the following final rules (and any rules and guidance issued pursuant to them) and, if appropriate, "suspend, revised or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules": Clean Power Plan; Clean Power Standards; and Federal Plan, Model Trading Rules, and Amendments to Framework Regulations.
  - Review the O&G NSPS final rule (June 3, 2016) (and any rules and guidance issued pursuant to it) and, if appropriate, "suspend, revise, or rescind the guidance, or publish for notice and comment proposed rules suspending, revising, or rescinding those rules".

Executive Order 13783 – Final Report

- "Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783" issued on Oct. 25, 2017.

- Identifies four key initiatives:
  - Comprehensive new source review reform
  - National ambient air quality standards reform
  - Robust evaluations of the employment effects of EPA regulations
  - A sector-based outreach program

- Report included consideration of other Administration initiates such as the Presidential Memorandum on permit streamlining and EO 13777 (Enforcing the Regulatory Reform Agenda).

- Appendix summarizes regulatory actions EPA took in response to EO 13783.

Executive Order 13766: Expediting Environmental Reviews and Approvals for High Priority Infrastructure Projects

- Signed on January 24, 2017
- CEQ is officially the lead on this EO, although Byron Brown in the Office of the Administrator has been a liaison on EPA work.
- Applies to all media (not just air), and also NEPA.
- "Infrastructure" seems to focus mainly on transportation, bridges, transmission pipelines, and highways.
- Some apparent overlap with "FAST-41" and there are discussions about whether/how to merge these activities.
  - Enacted in Dec. 2015, FAST-41 seeks to streamline timelines on authorizations associated with certain large infrastructure projects and provide a mechanism for coordination between relevant federal agencies that may be issuing authorizations for a single project. Statute identifies key criteria for qualifying projects which includes being subject to NEPA and exceeding a high cost threshold ($200 million), among other criteria.
  - A public permitting dashboard provides information about applicable projects. There are no projects involving air permitting at this time.

Executive Order 13771: Reducing Regulation and Controlling Regulatory Costs

- Signed on January 30, 2017, this order is also referred to as the "2 for 1" EO.
- OP is working with OMB on EPA related coordination.
- OMB recently issued government wide guidance:
  - "Interim Guidance Implementing Section 2 of the Executive Order of January 30, 2017, titled Reducing Regulation and Controlling Regulatory Costs", Feb 2, 2017
  - "Guidance Implementing Executive Order 13771, titled Reducing Regulation and Controlling Regulatory Costs", Apr 5, 2017

Executive Order 13777: Enforcing the Regulatory Reform Agenda

- Signed on February 24, 2017
- Establishes a Regulatory Reform Task Force in each agency.
- Samantha Dravis (AA for OP) is lead of EPA's Task Force.
- Task Force will make recommendations for existing regulations regarding their "repeal, replacement, or modification with the applicable law."
- EPA published a FR Notice on the "Evaluation of Existing Regulations" to collect information from stakeholders on April 11, 2017. Written comments were due to Docket # EPA-HQ-OA-2017-0190 by May 15, 2017.
- OAR has a website to support this effort: https://www.epa.gov/clean-air-act-overview/oar-regulatory-reform

Directive Promoting Transparency and Public Participation in Consent Decrees and Settlement Agreements

- Oct. 16, 2017 Directive from Administrator Pruitt

- Sets forth general path forward for Agency interaction with states and/or regulated entities regarding notices of intent to sue letters, complaints, petitions for review, consent decrees, and settlement agreements.

- Examples of information in directive include, but are not limited to:
  - Provide access via website for notices of intent to sue, petitions for review, and complaints
  - Take steps to achieve the participation of affected states and/or regulated entities in the consent and settlement agreement negotiation process.
  - Comply with Clean Air Act notification obligations for settlement agreements and consent decrees.

2015 Ozone NAAQS: Implementation-Related Rules/Guidance/Activities

- **Final National Ambient Air Quality Standards for Ozone Rule** signed October 1, 2015 (80 FR 65292), revising the primary and secondary 8-hour ozone standards to 0.070 ppm
  - Litigation on the level of the standard is being held in abeyance while EPA reviews the 2015 rule to determine whether the standards should be maintained, modified, or otherwise reconsidered
- **Proposed Rule: Implementation of the 2015 NAAQS for Ozone: Nonattainment Area Classifications and State Implementation Plan Requirements** published November 17, 2016 (81 FR 81276)
  - Proposed rule comment period closed February 13, 2017; timing of final rule TBD
- **The statutory deadline for designations is October 1, 2017**
  - The EPA Administrator may determine that an extension of time to complete designations, as permitted by the CAA, is necessary

2010 SO_2 NAAQS Designations: Round 1

- EPA revised **Primary NAAQS for Sulfur Dioxide (SO_2) standard** on June 3, 2010 to 75 ppb/1-hour (75 FR 35520)

- EPA designated 29 areas as nonattainment on July 25, 2013 (Round 1)
  - **Guidance for 1-hr SO_2 NAAQS NAA SIP Submissions** was issued on April 23, 2014
  - Attainment plans for the 29 areas were due April 4, 2015
  - EPA issued findings of failure to submit (FFS) attainment plans for 16 areas in 11 states, effective April 18, 2016 (81 FR 14736; published March 18, 2016)

- EPA is working with affected states to develop SIPs and to take action on submitted SIPs

2010 SO_2 Designations: Rounds 2 and 3

- Round 2: In 2016, EPA finalized designations for 65 areas: 7 nonattainment areas, 41 unclassifiable/attainment areas, and 17 unclassifiable areas
  - For 61 areas, effective date of designations was Sept. 12, 2016, and for the 4 nonattainment areas in this group the state attainment SIP is due March 12, 2018
  - For 4 areas in Texas, the effective date of designations was Jan. 12, 2017, and for the 3 nonattainment areas in this group the state attainment SIP is due July 12, 2018

- Round 3: On August 22, 2017, EPA notified states and tribes concerning any intended modifications to their designation recommendations ("120-day letters")
  - These responses included identification of 107 unclassifiable/attainment areas, 36 unclassifiable areas , and 11 potential nonattainment areas.
  - The notification of availability and public comment period was published on September 5, 2017 (82 FR 41903)
  - Comment period ends on Oct. 5, 2017
  - States requested to provide final input by October 23, 2017
  - EPA signs notice promulgating final SO2 area designations for Round 3 by no later than December 31, 2017

2010 SO_2 Designations: Round 4

- Round 3 SO_2 designations will designate all areas of the country, except those where states timely sited monitors consistent with the SO_2 Data Requirements Rule

- EPA will designate all remaining areas (approximately 50 areas) by the December 2020 consent decree deadline

Exceptional Events

- **On September 16, 2016, the EPA finalized the 2016 Revisions to the Exceptional Events Rule**, which addresses issues raised by stakeholders, increases the administrative efficiency, and reduces the burden of the Exceptional Event demonstrations process
  - https://www.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
  - Rule effective date was September 30, 2016; published in Federal Register on October 3, 2016 (81 FR 68216)
  - NRDC/Sierra Club has challenged the rule's natural event definition, which can include reasonably controlled anthropogenic sources – currently being briefed before D.C. Circuit Court

- So far in 2017, EPA has concurred on three demonstrations on ozone (CT, Ute Tribe, Washoe County)

- EPA continues to be engaged with stakeholders to seek feedback and identify opportunities to improve process and efficiency – our goal is continuous improvement

- We are interested in feedback regarding tools/resources to facilitate implementation of the rule revisions and realize all potential burden reductions

Coordination, Collaboration, and Communication—ALL CRITICAL!!!

- The Initial Notification Process should enable early engagement to establish mutual expectations to "right size" effort and assess the purpose for the data exclusion and what is needed for approvable demonstration based on the rule.

- EPA intends to conduct initial review of demonstrations within 120 days of submission, complete review within 12 months, and defer demonstrations that do not have regulatory significance within 60 days.

- Mitigation plan elements are intended to balance public notification of air quality and resources. Plans have minimum elements and must undergo public notice/comment; however, areas can leverage other plans/resources for mitigation plan elements.

Exceptional Events Implementation: Next Steps

- The 2016 rule revisions and final wildfire/ozone guidance were needed first steps, efficient and coordinated implementation is also critical. What is next?

- Continued development of exceptional events tools
  - Templates
  - Website updates
  - AQS modifications to reflect rule revisions guided by feedback from newly created AQS workgroup
  - Standardized metrics and tracking
  - Targeted efforts with FLMs – communications and tools
  - Best practices for multi-state exceptional events demonstrations

- Possible Additional Implementation Materials
  - Revisions to 2013 *Interim Exceptional Events Guidance Documents*
  - Stratospheric Ozone Intrusion Document
  - Alternate Paths for Data Exclusion Document
  - Prescribed Fire/Ozone Document

- EPA plans to transition to national electronic tracking system for exceptional events (similar to SPeCs for SIPs) in 2018

Exceptional Events Implementation: Available Resources

- Exceptional Events Website at http://www2.epa.gov/air-quality-analysis/treatment-data-influenced-exceptional-events
- Quick reference guide for exceptional events demonstrations
- Examples of reviewed exceptional event submissions
- Best practices documents
- Links to publicly available support information and tools
- Links to rule and guidance resources
  - Final rule
  - Final wildfire/ozone guidance
  - Fact sheets
  - 2013 interim guidance documents

Ozone Transport

- Congress established multiple CAA provisions that can be used to address interstate transport of air pollutants that are contributing to nonattainment or interfering with maintenance of NAAQS: section 110(a)(2)(D)(i)(I) (also known as the "good neighbor" provision), section 126 and section 176A

- The CAA envisions a SIP-led process; EPA is focused on a SIP first approach wherever possible

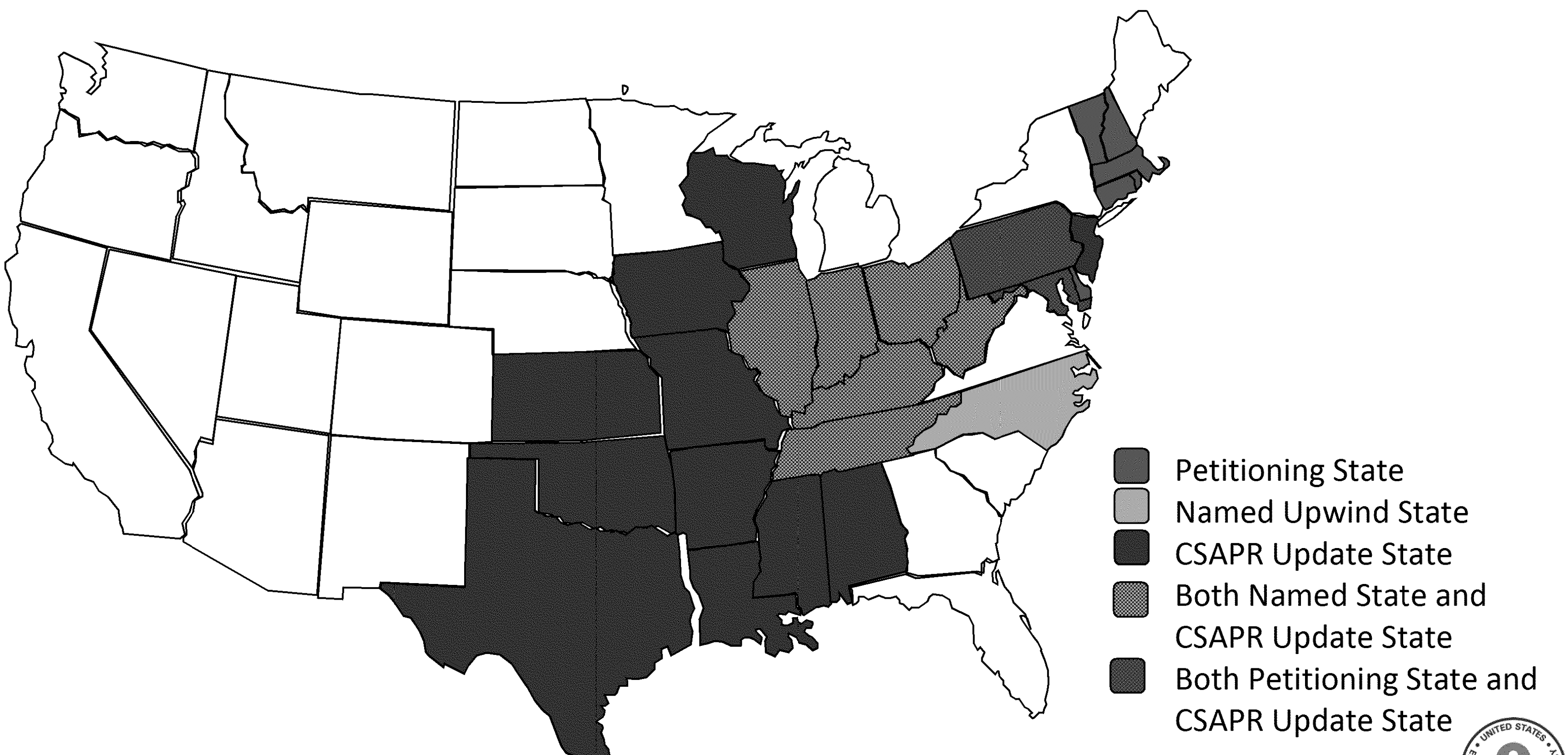
- States have asked EPA for information and guidance to enable states to develop approvable and timely transport SIPs to address regional (multi-state) air quality problems

Good Neighbor Transport SIPs for Ozone NAAQS

- **Section 110(a)(2)(D)(i)(I)** – (the "good neighbor" provision) requires upwind states to implement a share of the emission reductions needed for downwind areas to attain and maintain the NAAQS

- **Outstanding good neighbor obligations for the 2008 ozone NAAQS**
  - CSAPR Update was a partial remedy for 21 eastern states (full remedy for TN).
    - AL, AR, IL, IN, IA, KS, KY, LA, MD, MI, MS, MO, NJ, NY, OH, OK, PA, TX, VA, WV, and WI
  - CSAPR Update Rule did not address 2008 transport obligations for western states
  - There are 24 states for which EPA does not have a pending SIP and continues to have a FIP obligation.
    - * Kentucky – EPA is under a court-ordered deadline of June 30, 2018 for a full FIP; however, EPA can moot the FIP obligation if it fully approves a SIP from KY
    - * For other states, EPA has statutory FIP deadlines ranging from August 2017 to March 2019.
  - EPA is currently developing updated interstate ozone transport modeling using an analytic year of 2023 and hosted conference calls with MJOs and states in August to discuss plans for this modeling.

176A Petition and CSAPR Update States



Clean Air Act Section 126

Petitioning State	Response Deadlines	Named EGU Sources	Ozone NAAQS Cited
CT[1]	1/25/17	Brunner Island, PA	2008
DE (4 petitions)	3/5/17 4/7/17 7/9/17 8/3/17	1. Brunner Island, PA 2. Harrison, WV 3. Homer City, PA 4. Conemaugh, PA	2008 and 2015
MD[2]	7/15/17	36 EGUs at 19 facilities in IN, KY, OH, PA and WV	Emphasized 2008

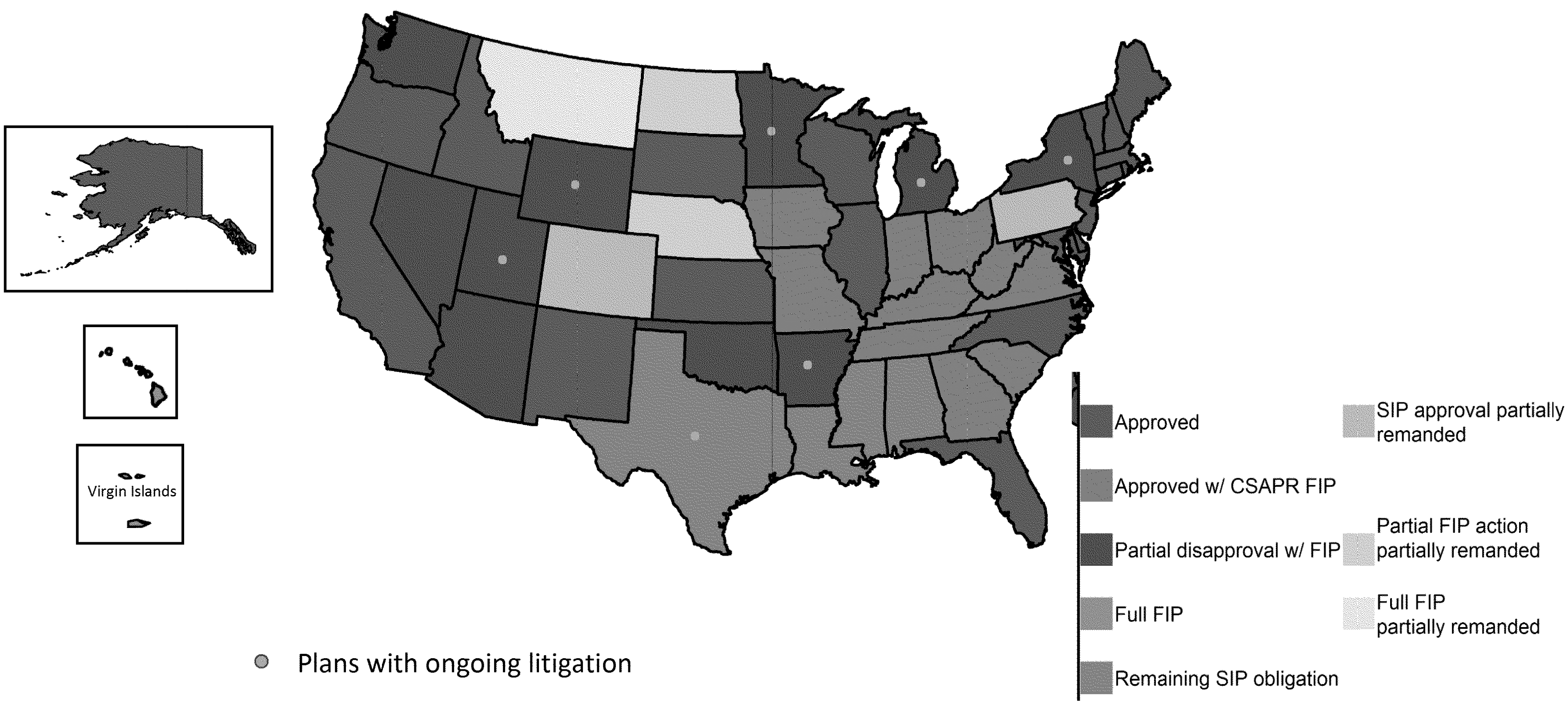
[1]On May 16, 2017, CT filed a mandatory duty suit in the U.S. District Court in Connecticut for EPA's failure to respond to its 126 petition by the January 2017 deadline. Sierra Club and the Connecticut Fund for the Environment have intervened as plaintiffs.
[2]On July 20, 2017, MD provided its notice of intent to sue for EPA's failure to respond to its 126 petition. Several environmental groups have also provided notice of their intent to sue on the same petition.

Cross-State Air Pollution Rule

- CSAPR (finalized July 2011) addresses interstate transport obligations for the 1997 ozone NAAQS (and the 1997 and 2006 $PM_{2.5}$ NAAQS)

- CSAPR Update (finalized September 7, 2016) updates CSAPR ozone season program by addressing summertime transport of ozone for the 2008 ozone NAAQS in the eastern US
  - Covers 22 eastern states and sets power sector ozone season NO_X emission budgets for each covered state starting with the 2017 ozone season (May 1, 2017)
  - Establishes a new ozone season NO_X allowance trading program for CSAPR Update states
  - Facilitates a smooth transition by creating a starting bank of allowances, converted from 2015-2016 allowances banked under the original CSAPR ozone season NO_X trading program
  - Responds to the July 2015 D.C. Circuit remand of CSAPR Phase 2 ozone season emission budgets for 11 states. EPA is also working to respond to the remand of the Phase 2 SO_2 emissions budgets. In November 2016, EPA proposed action and we expect to finalize action very soon.
  - Additional information at http://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update
  - Legal challenges to the CSAPR Update are currently pending in the United States Court of Appeals for the D.C. Circuit. Petitioners' briefs were filed on September 18, 2017 (EPA's brief is due December 18, 2017).

Regional Haze: Status of Actions from First Implementation Period



- Plans with ongoing litigation

Regional Haze Looking Forward: Planning for the Next Cycle of SIPs

- **Rule revisions were finalized on January 10, 2017 (82 FR 3078):**
  - Petitions for review were filed in the D.C. Circuit as well as petitions for reconsideration
- **On July 8, 2016 (81 FR 44608), EPA released draft guidance for two key aspects of the program:**
  - 1) Visibility Tracking – Tracking visibility progress based on impacts from controllable, anthropogenic emissions instead of all sources
  - 2) Reasonable Progress (RP) Guidelines – Guidance for evaluating the statutory factors and making decisions on RP controls
- EPA is currently considering public comments as we work to finalize the guidance document
- Timing for final guidance document: TBD

SSM SIP Call under Policy Review

- Final SSM SIP Action of 2015 concerned SIP provisions for treatment of excess emissions occurring during periods of startup, shutdown and malfunction (SSM)
  - Restated EPA's SSM Policy as it applied to SIPs with one change regarding affirmative defense (AD) provisions
  - Included SSM SIP Call that applied to 36 states (45 jurisdictions)
- Judicial review of the SSM Action is pending before the D.C. Circuit, but case is currently being held in abeyance to allow for review by the new administration

Title V Permitting

- On August 24, 2016, proposed the **Revisions to the Petition Provisions of the Title V Permitting Program** to increase transparency and stakeholder understanding of the petition process, as well as ensure that the Agency is able to efficiently address related programmatic and air quality issues (81 FR 57822)
  - The comment period closed on October 24, 2016 and EPA is in the process of reviewing the comments received. Timing: TBD

- On August 26, 2016, EPA proposed the **Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program** (81 FR 68110)
  - The public comment period closed on December 16, 2016 and EPA is currently reviewing comments. Timing: TBD

Title V Permitting

- Title V Program and Fee Evaluation Guidance
  - Satisfies EPA commitments to 2014 Office of Inspector General (OIG) report recommending enhanced oversight of state and local title V program fee practices
    - Guidance for EPA regions on conducting state and local title V program and fee evaluations
  - Discretionary for EPA regions and no specific requirements for state programs
  - Consistent with the principles and best practices for oversight of state permitting programs contained in the August 30, 2016 document *"Principles and Best Practices for Oversight of State Permitting Programs"*, developed by EPA's Cross-Media State Programs Health and Integrity Workgroup
- Timing: anticipate issuing final guidance in late 2017

Guidance on Significant Impact Levels (SILs) for Ozone and $PM_{2.5}$ in the Prevention of Significant Deterioration Permitting Program

- Draft guidance recommends SILs for Ozone and $PM_{2.5}$
  - A SIL is a compliance demonstration tool to help determine whether a proposed PSD source causes or contributes to a violation of the NAAQS or PSD increment
  - If a PSD applicant can show through air quality modeling that the projected impact from a proposed source is less than a SIL value for a particular pollutant, the permitting authority can conclude that the proposed source will not cause or contribute to a violation of a NAAQS or a PSD increment for that pollutant
- Draft guidance comment period from August 1, 2016 through September 30, 2016; comments under consideration
- Timing for final guidance issuance – TBD

SIP Processing Improvements

- EPA remains committed to reducing the SIP backlog and improving SIP processing times

- Trends in SIP processing:
  - Total pending SIPs reduced by 38% (between October 2013 and August 2017)
  - Historic backlogged SIPs reduced by 78% (between October 2013 and August 2017)

- SIP management improvement efforts ongoing
  - SIP management plans continue to provide opportunities for EPA regional offices and states to engage on setting SIP action priorities
  - EPA emphasizing early engagement with air agencies
  - EPA maintaining emphasis on internal SIP processing improvements
    - Identification and implementation of best practices in SIP processing and collaboration between states and EPA will help ensure continuous improvement
    - Significant investment in IT improvements will also contribute in this area

SIP Processing Improvements: State Plan Electronic Collection System (SPeCS)

- SPeCS will provide an efficient electronic system for:
  - State submission and tracking of multiple types of plans
  - EPA review process and requirements tracking
  - Public dashboard with SIP Status reports and info on state submissions and EPA actions
- Benefits: reduce paper/mailing costs/storage, save staff time and resources, integrate multiple legacy tracking systems, increase transparency, lead to more efficient process
- EPA greatly appreciates input from state/local officials through Integrated Project Team, webinars and Regional Hub calls, and recent beta-testing
- <u>System launch and training for State and EPA users: December 2017/January 2018</u>

SPeCS for SIPs: Major Components

Plan Collection Interface

- ***For use by air agency staff***
- Electronic file upload capability; builds upon May 2017 eSIP enhancement
- Enables air agency to identify specific requirements included in plan
- State landing page provides info/links for all past and pending submissions

EPA Plan Review Clearinghouse

- ***For use by EPA***
- Facilitates concurrent review by multiple EPA offices
- Tracks compliance with SIP requirements
- Electronic storage and online searching of documents

Public Dashboard

- ***For use by the public and states***
- National and state SIP status information
- Links to submitted plans, FR notices, and related information

Questions and Comments

APPENDIX

NAAQS Reviews: Status Update

(September 2017)

	Ozone	Lead	Primary NO_2	Primary SO_2	Secondary (Ecological) NO_2, SO_2, PM[1]	PM[2]	CO
Last Review Completed (final rule signed)	Oct. 2015	Sept 2016	Jan 2010	Jun 2010	Mar 2012	Dec 2012	Aug 2011
Recent or Upcoming Major Milestone(s)[3]	TBD[4]	TBD[4]	July 14, 2017 Proposal Sept 25, 2017 Public Comment Closes April 6, 2018 Final	Summer 2017 Draft PA and REA May 25, 2018 Proposal Jan 28, 2019 Final	May 24-25, 2017 CASAC review of 1st Draft ISA Summer 2018 2nd Draft ISA REA Planning Document	Dec 2016 Final IRP Spring/Summer 2018 1st draft ISA REA Planning Document	TBD[4]

Additional information regarding current and previous NAAQS reviews is available at:
http://www.epa.gov/ttn/naaqs/

[1] Combined secondary (ecological effects only) review of NO_2, SO_2, and PM
[2] Combined primary and secondary (non-ecological effects) review of PM
[3] IRP – Integrated Review Plan; ISA – Integrated Science Assessment; REA – Risk and Exposure Assessment; PA – Policy Assessment
[4] TBD = to be determined

Anticipated NAAQS Implementation Milestones

(September 2017)

Pollutant	Final NAAQS Date	Designations Effective	Infrastructure SIP Due	Attainment Plans Due	Attainment Date
$PM_{2.5}$ (2006)	Oct 2006	Dec 2009	Oct 2009	Dec 2014	Dec 2015 (Mod) Dec 2019 (Ser)
Pb (2008)	Oct 2008	Dec 2010-2011	Oct 2011	June 2012-2013	Dec 2015-2019
$PM_{2.5}$ (2012)	Dec 2012	Apr 2015	Dec 2015	Oct 2016 (Mod)	Dec 2021 (Mod) Dec 2025 (Ser)
NO_2 (2010) (primary)	Jan 2010	Feb 2012	Jan 2013	N/A	N/A
SO_2 (2010) (primary)	June 2010	Oct 2013, Sept 2016 (+2 rounds)	June 2013	April 2015, March 2018 (2019, 2022)	Oct 2018, Sept 2021 (2023, 2026)
Ozone (2008)	Mar 2008	July 2012	Mar 2011	Mid 2015-2016	Mid 2015-2032
Ozone (2015)	Oct 2015	TBD	Oct 2018	TBD	TBD

To: Wood, Anna[Wood.Anna@epa.gov]
Cc: Johnson, Yvonne W[Johnson.Yvonnew@epa.gov]
From: Long, Pam
Sent: Thur 8/24/2017 12:47:11 PM
Subject: RE: Heads Up and Updates...
NACAA 2017 Spring Full Deck w_TPs 8-18-17.pptx

From: Wood, Anna
Sent: Thursday, August 24, 2017 8:46 AM
To: Long, Pam <Long.Pam@epa.gov>
Cc: Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>
Subject: Re: Heads Up and Updates...

Thx Pam, please send me the latest slide deck - thx

Yay - **Ex. 6 - Personal Privacy**

Sent from my iPhone

On Aug 24, 2017, at 8:35 AM, Long, Pam <Long.Pam@epa.gov> wrote:

I am out of the office tomorrow, Monday 8/28 and 8/29. Returning 8/30. Yvonne is planning to return on Monday.

The only thing right now I have on my plate that is outstanding on Yvonne's front is:

1. Request for background on Sheboygan (SLPG) – due today
2. Registration for Anna for her NACAA meeting – waiting on the

approved registration form – due by 8/25

I have the master of the slide deck for NACAA that I have tweaked here and there that I will share with Yvonne.

I have not seen where a pre-brief for Steve we submitted on 8/15 on "Clean Air Act Ozone Transport Program and Key Milestones" has been scheduled. I have a question in to Peter about it. The meeting with Sarah is 9/12. All other meetings submitted have been scheduled.

I plan to shut my door most of the day to work on the Fall reg. agenda (first round is due tomorrow).

Let me know if there is anything outstanding I am missing.

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Thur 4/6/2017 8:20:19 PM
Subject: full deck presentation -- Update April 6_TPs.pptx
Update April 6_TPs.pptx

I left you a hardcopy of the latest full deck which incorporates all of the slides from the recent AAPCA meeting.

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Wood, Anna[Wood.Anna@epa.gov]
From: Johnson, Yvonne W
Sent: Tue 3/14/2017 2:22:44 PM
Subject: informational briefings
Anna Wood SO2 Nonattainment Areas 2 22 17 lw 800.pptx
ExEvents_101briefing_v3.pptx
O3_impl_overview+TP_DRAFT_2-28-17.pptx
PM25 Implementation 2_21_2017.version given to Anna.pptx
SSM SIP Action of 2015_briefing for AW_2017-02-14 1434.pptx

Thank you,

Yvonne W. Johnson

Special Assistant to the Director

Air Quality Policy Division

Office of Air Quality Planning & Standards

U.S. Environmental Protection Agency

919-541-3921

johnson.yvonnew@epa.gov

To: Johnson, Yvonne W[johnson.yvonnew@epa.gov]
From: Wood, Anna
Sent: Wed 9/20/2017 7:33:19 PM
Subject: NACAA FULL DECK with all slides including Vera's question slide
NACAA 2017 Fall Full Deck w_TPs_sept 20.pptx

Hi, here you go, please take one last look—thx!

Anna Marie Wood

Director, Air Quality Policy Division

OAQPS, U.S. EPA

109 T.W. Alexander Drive

Research Triangle Park, NC 27711

(919) 541-3604

To: Garcia, David[Garcia.David@epa.gov]
From: Wood, Anna
Sent: Thur 10/19/2017 9:12:43 PM
Subject: RE: Request for NSR Workshop Manual
Final Reform Rule.pdf

Hi David, attached is the final 2002 NSR Reform Rule—it provides a good overview of NSR and the aspects we changed in the program as part of the rulemaking. The first web link will provide a general overview of the NSR and minor NSR Programs. The second link provides a link to all of the NSR actions, including those related to reform and the actions we took after 2002 to respond to 2 court decisions vacating/upholding different aspects of reform changes. I hope these resources are helpful, Anna

General Information about New Source Review

https://www.epa.gov/nsr/learn-about-new-source-review

Links to NSR Reform regulatory actions (including NSR Reform rule and additional actions in response to court's vacatur of certain elements)

https://www.epa.gov/nsr/nsr-regulatory-actions#nsrreform

From: Garcia, David
Sent: Thursday, October 19, 2017 1:17 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: RE: Request for NSR Workshop Manual

You're the greatest, thank you!!

David F. Garcia, P.E.

Acting Director

International Compliance Assurance Division

Office of Enforcement and Compliance Assurance

1200 Pennsylvania Ave. NW

Washington DC 20460

Office # 202 564 6483

From: Wood, Anna
Sent: Thursday, October 19, 2017 12:20 PM
To: Garcia, David <Garcia.David@epa.gov>
Subject: RE: Request for NSR Workshop Manual

I am asking my folks to pull together a couple of documents for you that might be helpful, please stay tuned. Thx

From: Garcia, David
Sent: Wednesday, October 18, 2017 5:20 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: RE: Request for NSR Workshop Manual

Hi Anna,

Thank you, for the input. I guess you can tell I am a bit dated. By any chance is there a similar NSR 101 manual or document that contains latest reform efforts? if not, that is fine. I just believe folks around here need to appreciate the complexity of the NSR program.

David F. Garcia, P.E.

Acting Director

International Compliance Assurance Division

Office of Enforcement and Compliance Assurance

1200 Pennsylvania Ave. NW

Washington DC 20460

Office # 202 564 6483

From: Wood, Anna
Sent: Wednesday, October 18, 2017 4:35 PM
To: Garcia, David <Garcia.David@epa.gov>
Subject: Request for NSR Workshop Manual

Hi David, here is the link to the NSR manual. I also left you a voice mail. The manual is quite dated and does not reflect the changes we made to the NSR program in NSR Reform 1 in 2002 nor the regulation of GHGs under PSD and the recent revisions to Appendix W related to modeling. Thanks, Anna

https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990

Anna Marie Wood

Director, Air Quality Policy Division

OAQPS, U.S. EPA

109 T.W. Alexander Drive

Research Triangle Park, NC 27711

(919) 541-3604

Federal Register

Tuesday,
December 31, 2002

Part III

Environmental Protection Agency

40 CFR Parts 51 and 52

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR); Final Rule and Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[AD–FRL–7414–5]

RIN 2060–AE11

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is revising regulations governing the New Source Review (NSR) programs mandated by parts C and D of title I of the Clean Air Act (CAA or Act). These revisions include changes in NSR applicability requirements for modifications to allow sources more flexibility to respond to rapidly changing markets and to plan for future investments in pollution control and prevention technologies. Today's changes reflect EPA's consideration of discussions and recommendations of the Clean Air Act Advisory Committee's (CAAAC) Subcommittee on NSR, Permits and Toxics, comments filed by the public, and meetings and discussions with interested stakeholders. The changes are intended to provide greater regulatory certainty, administrative flexibility, and permit streamlining, while ensuring the current level of environmental protection and benefit derived from the program and, in certain respects, resulting in greater environmental protection.

EFFECTIVE DATE: This final rule is effective on March 3, 2003.

ADDRESSES: *Docket.* Docket No. A–90–37, containing supporting information used to develop the proposed rule and the final rule, is available for public inspection and copying between 8 a.m. and 4:30 p.m., Monday through Friday (except government holidays) at the Air and Radiation Docket and Information Center (6102T), Room B–108, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC 20460; telephone (202) 566–1742, fax (202) 566–1741. A reasonable fee may be charged for copying docket materials. *Worldwide Web (WWW).* In addition to being available in the docket, an electronic copy of this final rule will also be available on the WWW through the Technology Transfer Network (TTN). Following signature, a copy of the rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules: *http://www.epa.gov/ttn/oarpg.*

FOR FURTHER INFORMATION CONTACT: Ms. Lynn Hutchinson, Information Transfer and Program Integration Division (C339–03), U.S. EPA Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina 27711, telephone 919–541–5795, or electronic mail at *hutchinson.lynn@epa.gov,* for general questions on this rule. For questions on baseline emissions determination or the actual-to-projected-actual applicability test, contact Mr. Dan DeRoeck, at the same address, telephone 919–541–5593, or electronic mail at *deroeck.dan@epa.gov.* For questions on Plantwide Applicability Limitations (PALs), contact Mr. Raj Rao, at the same address, telephone 919–541–5344, or electronic mail at rao.raj@epa.gov. For questions on Clean Units, contact Mr. Juan Santiago, at the same address, telephone 919–541–1084, or electronic mail at santiago.juan@epa.gov. For questions on Pollution Control Projects (PCPs), contact Mr. Dave Svendsgaard, at the same address, telephone 919–541–2380, or electronic mail at *svendsgaard.dave@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities

Entities potentially affected by this final action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups.

Industry group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122
Petroleum Refining	291	32411
Chemical Processes	281	325181, 32512, 325131, 325182, 211112, 325998, 331311, 325188
Natural Gas Transport	492	48621, 22121
Pulp and Paper Mills	261	32211, 322121, 322122, 32213
Paper Mills	262	322121, 322122
Automobile Manufacturing	371	336111, 336112, 336712, 336211, 336992, 336322, 336312, 33633, 33634, 33635, 336399, 336212, 336213
Pharmaceuticals	283	325411, 325412, 325413, 325414

[a] Standard Industrial Classification

[b] North American Industry Classification System.

Entities potentially affected by this final action also include State, local, and tribal governments that are delegated authority to implement these regulations.

Outline. The information presented in this preamble is organized as follows:

I. Overview of Today's Final Action
A. Background
B. Introduction
C. Overview of Final Actions
1. Determining Whether a Proposed Modification Results in a Significant Emissions Increase
2. CMA Exhibit B
3. Plantwide Applicability Limitations (PALs)
4. Clean Units
5. Pollution Control Projects (PCPs)
6. Major NSR Applicability
7. Enforcement
8. Enforceability
II. Revisions to the Method for Determining Whether a Proposed Modification Results in a Significant Emissions Increase
A. Introduction
B. What We Proposed and How Today's Action Compares
C. Baseline Actual Emissions For Existing Emissions Units Other than EUSGUs
D. The Actual-to-projected-actual Applicability Test
E. Clarifying Changes to WEPCO Provisions for EUSGUs
F. The "Hybrid" Applicability Test
G. Legal Basis for Today's Action
H. Response to Comments and Rationale for Today's Actions
III. CMA Exhibit B
IV. Plantwide Applicability Limitations (PALs)
A. Introduction
B. Relevant Background
C. Final Regulations for Actuals PALs
D. Rationale for Today's Final Action on Actuals PALs
V. Clean Units

A. Introduction
B. Summary of 1996 Clean Unit Proposal
C. Final Regulations for Clean Units
D. Legal Basis for the Clean Unit Test
E. Summary of Major Comments and Responses
VI. Pollution Control Projects (PCPs)
A. Description and Purpose of This Action
B. What We Proposed and How Today's Action Compares To It
C. Legal Basis for PCP
D. Implementation
VII. Listed Hazardous Air Pollutants
VIII. Effective Date for Today's Requirements
IX. Administrative Requirements
A. Executive Order 12866—Regulatory Planning and Review
B. Executive Order 13132—Federalism
C. Executive Order 13175—Consultation and Coordination with Indian Tribal Governments
D. Executive Order 13045—Protection of Children from Environmental Health Risks and Safety Risks
E. Unfunded Mandates Reform Act of 1995
F. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 *et seq.*
G. Paperwork Reduction Act
H. National Technology Transfer and Advancement Act of 1995
I. Congressional Review Act
J. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
X. Statutory Authority
XI. Judicial Review

I. Overview of Today's Final Action

A. Background

We[1] proposed revisions to the NSR rules in a notice published in the **Federal Register** on July 23, 1996 (61 FR 38250). On July 24, 1998, we published a notice (63 FR 39857) to solicit further comment on two specific aspects of the proposed revisions. Today's **Federal Register** action announces EPA's final action on the proposed revisions for baseline emissions determinations, the actual-to-future-actual methodology, actuals PALs, Clean Units, and PCPs. We have not made final determinations on any other proposed changes to the regulations.

Today's actions finalize these changes to the regulations for both the approval and promulgation of implementation plans and requirements for preparation, adoption, and submittal of implementation plans governing the NSR programs mandated by parts C and D of title I of the Act. We also proposed conforming changes to 40 CFR (Code of Federal Regulations) part 51, appendix S, and part 52.24. Today we have not included the final regulatory language for these regulations. It is our intention to include regulatory changes that conform appendix S and 40 CFR 52.24 to today's final rules in any final regulations that set forth an interim implementation strategy for the 8-hour ozone standard. We intend to finalize changes to these sections precisely as we have finalized requirements for other parts of the program. Because these are conforming changes and the public has had an opportunity for review and comment, we will not be soliciting additional comments before we finalize them.

The major NSR program contained in parts C and D of title I of the Act is a preconstruction review and permitting program applicable to new or modified major stationary sources of air pollutants regulated under the Act. In areas not meeting health-based National Ambient Air Quality Standards (NAAQS) and in ozone transport regions (OTR), the program is implemented under the requirements of part D of title I of the Act. We call this program the ''nonattainment'' NSR program. In areas meeting NAAQS (''attainment'' areas) or for which there is insufficient information to determine whether they meet the NAAQS (''unclassifiable'' areas), the NSR requirements under part C of title I of the Act apply. We call this program the Prevention of Significant Deterioration (PSD) program. Collectively, we also commonly refer to these programs as the major NSR program. These regulations are contained in 40 CFR 51.165, 51.166, 52.21, 52.24, and part 51, appendix S.

The NSR provisions of the Act are a combination of air quality planning and air pollution control technology program requirements for new and modified stationary sources of air pollution. In brief, section 109 of the Act requires us to promulgate primary NAAQS to protect public health and secondary NAAQS to protect public welfare. Once we have set these standards, States must develop, adopt, and submit to us for approval a State Implementation Plan (SIP) that contains emission limitations and other control measures to attain and maintain the NAAQS and to meet the other requirements of section 110(a) of the Act.

Each SIP is required to contain a preconstruction review program for the construction and modification of any stationary source of air pollution to assure that the NAAQS are achieved and maintained; to protect areas of clean air; to protect Air Quality Related Values (AQRVs) (including visibility) in national parks and other natural areas of special concern; to assure that appropriate emissions controls are applied; to maximize opportunities for economic development consistent with the preservation of clean air resources; and to ensure that any decision to increase air pollution is made only after full public consideration of all the consequences of such a decision.

For newly constructed, ''greenfield'' sources, the determination of whether an activity is subject to the major NSR program is fairly straightforward. The Act, as implemented by our regulations, sets applicability thresholds for major sources in nonattainment areas [potential to emit (PTE) above 100 tons per year (tpy) of any pollutant subject to regulation under the Act, or smaller amounts, depending on the nonattainment classification] and attainment areas (100 or 250 tpy, depending on the source type). A new source with a PTE at or above the applicable threshold amount ''triggers,'' or is subject to, major NSR.

The determination of what should be classified as a modification subject to major NSR presents more difficult issues. The modification provisions of the NSR program in parts C and D are based on the definition of modification in section 111(a)(4) of the Act: the term ''modification'' means ''any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' That definition contemplates that, first, you will determine whether a physical or operational change will occur. If so, then you will proceed to determine whether the physical or operational change will result in an emissions increase over baseline levels.

The expression ''any physical change * * * or change in the method of operation'' in section 111(a)(4) of the Act is not defined. We have recognized that Congress did not intend to make every activity at a source subject to the major NSR program. As a result, we have previously adopted several exclusions from what may constitute a ''physical or operational change.'' For instance, we have specifically recognized that routine maintenance, repair and replacement, and changes in hours of operation or in the production rate are not considered a physical change or change in the method of

[1] In this preamble the term ''we'' refers to EPA and the term ''you'' refers to major stationary sources of air pollution and their owners and operators. All other entities are referred to by their respective names (for example, reviewing authorities.)

operation within the definition of major modification.[2]

We have likewise addressed the scope of the statutory definition of modification by excluding all changes that do not result in a ''significant'' emissions increase from a major source.[3] This regulatory framework applies the major NSR program at existing sources to only ''major modifications'' at major stationary sources.

One key attribute of the major NSR program in general is that you may ''net'' modifications out of review by coupling proposed emissions increases at your source with contemporaneous emissions reductions. Thus, under regulations we promulgated in 1980, you may modify, or even completely replace, or add, emissions units without obtaining a major NSR permit, so long as ''actual emissions'' do not increase by a significant amount over baseline levels at the plant as a whole.

Applicability of the major NSR program must be determined in advance of construction and is pollutant-specific. In cases involving existing sources, this requires a pollutant-by-pollutant determination of the emissions change, if any, that will result from the physical or operational change. Our 1980 regulations implementing the PSD and nonattainment major NSR programs thus inquire whether the proposed change constitutes a ''major modification,'' that is, a physical change or change in the method of operation ''that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.'' A ''net emissions increase'' is defined as the increase in ''actual emissions'' from the particular physical or operational change (taking into account the use of emissions control technology and restrictions on hours of operation or rates of production where such controls and restrictions are enforceable), together with your other contemporaneous increases or decreases in actual emissions.[4] In order to trigger applicability of the major NSR program, the net emissions increase must be ''significant.''[5]

Before today's changes, our regulations generally defined actual emissions as ''the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation.'' The reviewing authorities will allow use of a different time period ''upon a determination that it is more representative of normal source operation.'' We have historically used the 2 years immediately preceding the proposed change to establish a source's actual emissions. However, in some cases we have allowed use of an earlier period.

With respect to changes at existing sources, a prediction of whether the physical or operational change would result in a significant net increase in your actual emissions following the change was thus necessary. In part, this involved a straightforward and readily predictable engineering judgment—how would the change affect the emission factor or emissions rate of the emissions units that are to be changed.

Before today's changes, the regulations provided that when your emissions unit, other than an electric utility steam generating unit (EUSGU), ''has not begun normal operations,'' actual emissions equal the PTE of the unit. When you have not begun normal operations following a change, you must assume that your source will operate at its full capacity year round, that is, at its full emissions potential. This is referred to as the actual-to-potential test. You may avoid the need for an NSR permit by reducing your source's potential emissions through the use of enforceable restrictions to pre-modification actual emissions levels plus an amount that is less than ''significant''.

In 1992, we promulgated revisions to our applicability regulations creating special rules for physical and operational changes at EUSGUs. *See* 57 FR 32314 (July 21, 1992).[6] In this rule, prompted by litigation involving the Wisconsin Electric Power Company (WEPCO) and commonly referred to as the ''WEPCO rule,'' we adopted an actual-to-future-actual methodology for all changes at EUSGUs except the construction of a new electric generating unit or the replacement of an existing emissions unit. Under this methodology, the actual annual emissions before the change are compared with the projected actual emissions after the change to determine if a physical or operational change would result in a significant increase in emissions. To ensure that the projection is valid, the rule requires the utility to track its emissions for the next 5 years and provide to the reviewing authority information demonstrating that the physical or operational change did not result in an emissions increase.

In promulgating the WEPCO rule, we also adopted a presumption that utilities may use as baseline emissions the actual annual emissions from any 2 consecutive years within the 5 years immediately preceding the change.

In attainment areas, once major NSR is triggered, you must, among other things, install best available control technology (BACT) and conduct modeling and monitoring as necessary. If your source is located in a nonattainment area, you must install technology that meets the lowest achievable emissions rate (LAER), secure emissions reductions to offset any increases above baseline emission levels, and perform other analyses.

B. Introduction

Today's final regulations were proposed as part of a larger regulatory package on July 23, 1996 (61 FR 38250). That package proposed a number of changes to our existing major NSR requirements. (Please refer to the outline of that proposed rulemaking for a complete list of changes that were proposed to our existing regulations.) On July 24, 1998, we published a **Federal Register** Notice of Availability (NOA) that requested additional comment on three of the proposed changes: determining baseline emissions, actual-to-future-actual methodology, and PALs. Following the 1996 proposals, we held two public hearings and more than 50 stakeholder meetings. Environmental groups, industry, and State, local, and Federal agency representatives participated in these many discussions.

In May 2001, President Bush's National Energy Policy Development Group issued findings and key recommendations for a National Energy Policy. This document included numerous recommendations for action, including a recommendation that the EPA Administrator, in consultation with the Secretary of Energy and other relevant agencies, review NSR regulations, including administrative interpretation and implementation. The recommendation requested that we issue a report to the President on the impact of the regulations on investment

[2] *See* 40 CFR 52.21(b)(2).

[3] *See* 40 CFR 52.21(b)(23).

[4] In approximate terms, ''contemporaneous'' emissions increases or decreases are those that have occurred between the date 5 years immediately preceding the proposed physical or operational change and the date that the increase from the change occurs. *See*, for example, § 52.21(b)(3)(ii).

[5] Once a modification is determined to be major, the PSD requirements apply only to those specific pollutants for which there would be a significant net emissions increase. See, for example, § 52.21(j)(3) (BACT) and § 52.21(m)(1)(b) (air quality analysis).

[6] The regulations define ''electric utility steam generating units'' as any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 megawatts (MW) of electrical output to any utility power distribution system for sale. *See*, for example, § 51.166(b)(30).

in new utility and refinery generation capacity, energy efficiency, and environmental protection.

In response, in June 2001, we issued a background paper giving an overview of the NSR program. This paper is available on the Internet at *http://www.epa.gov/air/nsr-review/background.html.* We solicited public comments on the background paper and other information relevant to the New Source Review 90-day Review and Report to the President. During our review of the NSR program, we met with more than 100 groups, held four public meetings around the country, and received more than 130,000 written comments. Our report to the President and our recommendations in response to the energy policy were issued on June 13, 2002. A copy of this information is available at *http://www.epa.gov/air/nsr-review/.* We expect that our recommendations in response to the energy policy will be reflected in the future in various programs and regulatory actions. Today's actions implement several of those recommendations.

Today, we are finalizing five actions that we previously proposed in 1996 (three of which were re-noticed in the 1998 NOA). We are not taking final action on any of the remaining issues in the 1996 proposal at this time. We have not decided what final action we will take on those issues.

C. Overview of Final Actions

Today we are taking final action on five changes to the NSR program that will reduce burden, maximize operating flexibility, improve environmental quality, provide additional certainty, and promote administrative efficiency. These elements include baseline actual emissions, actual-to-projected-actual emissions methodology, PALs, Clean Units, and PCPs. We are also codifying our longstanding policy regarding the calculation of baseline emissions for EUSGUs. In addition, we are responding to comments we received on a proposal to adopt a methodology, developed by the American Chemistry Council (formerly known as the Chemical Manufacturers Association (CMA)) and other industry petitioners, to determine whether a source has undertaken a modification based on its potential emissions. We are including a new section in today's final rules that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. Finally, we have codified a new definition of ''regulated NSR pollutant'' that clarifies which pollutants are regulated under the Act for purposes of major NSR.

This section briefly introduces each improvement. Detailed discussions of the improvements are found in sections II through VII of this preamble.

1. Determining Whether a Proposed Modification Results in a Significant Emissions Increase

Today we are finalizing two changes to our existing major NSR regulations that will affect how you calculate emissions increases to determine whether physical changes or changes in the method of operation trigger the major NSR requirements. First, we have a new procedure for determining ''baseline actual emissions.'' That is, the relevant terminology for calculating pre-change emissions for most applications is now ''baseline actual emissions'' rather than ''actual emissions.'' You may use any consecutive 24-month period in the past 10 years to determine your baseline actual emissions. Second, we are supplementing the existing actual-to-potential applicability test with an actual-to-projected-actual applicability test for determining if a physical or operational change at an existing emissions unit will result in an emissions increase. Notwithstanding the new test, you will still have the ability to conduct an actual-to-potential type test within the new actual-to-projected-actual applicability test. In this case, you will not be subject to recordkeeping requirements that are being established and would otherwise apply as part of the new actual-to-projected actual applicability test.

For EUSGUs, we are making several changes to the existing procedures and are codifying our current policy for calculating the baseline actual emissions. That is, the baseline actual emissions for EUSGUs is the average rate, in tpy, at which that unit actually emitted the pollutant during a 2-year (consecutive 24-month) period within the 5-year period immediately preceding when the owner or operator begins actual construction. We are also retaining the option that allows the use of a different time period if the reviewing authority determines it is more representative of normal source operation.

2. CMA Exhibit B

As described in section I.C.1 above, we have decided to adopt an actual-to-projected-actual methodology, combined with a revised process to determine baseline emissions, to use in determining when sources are considered to have made a modification and are thereby subject to NSR. We are not adopting the methodology based on potential emissions as discussed in the CMA Exhibit B proposal. *See* section III of this preamble for a discussion of the comments we received on this proposal and our responses.

3. Plantwide Applicability Limitations

A PAL is a voluntary option that will provide you with the ability to manage facility-wide emissions without triggering major NSR review. We believe that the added flexibility provided under a PAL will facilitate your ability to respond rapidly to changing market conditions while enhancing the environmental protection afforded under the program.

Today we are promulgating a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap (that is, an actuals PAL), then these regulations will allow you to avoid the major NSR permitting process when you make alterations to the facility or individual emissions units. In return for this flexibility, you must monitor emissions from all of your emissions units under the PAL. The benefit to you is that you can alter your facility without first obtaining a Federal NSR permit or going through a netting review. A PAL will allow you to make changes quickly at your facility. If you are willing to undertake the necessary recordkeeping, monitoring, and reporting, a PAL offers you flexibility and regulatory certainty.

4. Clean Units

We are promulgating a new type of applicability test for emissions units that are designated as Clean Units. The new applicability test recognizes that when you go through major NSR review and install BACT or LAER, you may make any changes to the Clean Unit without triggering an additional major NSR review, if the project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or LAER and the project would not alter any physical or operational characteristics that formed the basis for the BACT or LAER determination. If the project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT or LAER or would alter any physical or operational characteristics that formed the basis for the BACT or LAER determination, you lose Clean Unit status. You may still proceed with the project without triggering major NSR review, if the increase is not a significant net emissions increase. Emissions units that have not been through major NSR may still qualify for Clean Unit status if they demonstrate that the emissions control level is comparable to BACT or LAER. Clean Unit status will be valid for up to a 10-year period. The new applicability test does not exclude consideration of physical changes or changes in the method of operation of Clean Units from major NSR, but rather changes the way emissions increases are calculated for these changes. This new applicability test therefore protects air quality, creates incentives for sources to install state-of-the-art controls, provides flexibility for sources, and promotes administrative efficiency.

5. Pollution Control Projects

Today's rule contains a new list of environmentally beneficial technologies that qualify as PCPs for all types of sources. Installation of a PCP is not subject to the major modification provisions. An owner or operator installing a listed PCP automatically qualifies for the exclusion if there is no adverse air quality impact—that is, if it will not cause or contribute to a violation of NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager (FLM) and for which information is available to the general public. The PCPs that are not listed in today's rules may also qualify for the PCP Exclusion if the reviewing authority determines on a case-specific basis that a non-listed PCP is environmentally beneficial when used for a particular application. Also, in the future, we may add to the listed PCPs through a rulemaking that provides for public notice and opportunity for comment. The PCP Exclusion allows sources to install emissions controls that are known to be environmentally beneficial. These provisions thus offer flexibility while improving air quality.

6. Major NSR Applicability

We have briefly described the new provisions for baseline actual emissions, actual-to-projected-actual methodology, PALs, and Clean Units. Sections II, IV, and V describe the new provisions in detail. These provisions offer major new changes to NSR applicability, especially regarding how a major modification is determined. The major NSR applicability provisions have developed over time and therefore have been added to the NSR rules in a piecemeal fashion. In today's final rules we are including a new section that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules. For each applicability option, we describe how a major modification is determined in detail. You'll find this new applicability "roadmap" in §§ 51.165(a)(2), 51.166(a)(7), and 52.21(a)(2). To summarize, the various provisions for major modifications are now as follows.

- Actual-to-projected-actual applicability test for all existing emissions units. (Including an actual-to-potential option)
- Actual-to-potential test for any new unit, including EUSGUs.
- The Clean Unit Test for existing emissions units with Clean Unit status.
- The hybrid test for modifications with multiple types of emissions units. (Used when a physical or operational change affects a combination of more than one type of unit.)

We describe actuals PALs, which are an alternative way of complying with major NSR, in section IV of this preamble. If you have a PAL, as long as you are complying with the PAL requirements, any physical or operational changes are not major modifications.

We have revised the definition of major modification to clarify what has always been our policy—that determining whether a major modification has occurred is a two-step process. The new definition of major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: (1) A significant emissions increase of a regulated NSR pollutant; and (2) a significant net emissions increase of that pollutant from the major stationary source." We have also revised the definitions of actual emissions, emissions unit, net emissions increase, and construction. We have deleted the word "actual" as related to emissions from the definition of "construction." This change was necessary because of how the definition of "actual emissions" is used in the final rule, but the deletion is not intended to change any meaning in the term "construction." We have added new definitions for baseline actual emissions, projected actual emissions, project, and significant emissions increase. These revisions and additions implement our new provisions for major modifications under the actual-to-projected-actual applicability test, actual-to-potential test, Clean Unit Test, and hybrid test. You will find a complete discussion of the Clean Unit Test, including how modifications to Clean Units are treated, in section V of this preamble. The other tests are discussed in section II.

"Actual emissions," as the term has been historically applied, will still be used to determine air quality impacts (for example, compliance with NAAQS, PSD increments, and AQRVs) and to compute the required amount of emissions offsets.

To further clarify major NSR applicability in one location, we have moved § 51.166(i)(1) through (3) and § 52.21(i)(1) through (3) into the new applicability sections at § 51.166(a)(7) and § 52.21(a)(2). These provisions clarify that you must obtain a permit before you begin construction (including for major modifications), that the provisions apply for each regulated NSR pollutant that your source emits, and that the provisions apply to any source located in the area designated as attainment or unclassifiable (for §§ 51.166 and 52.21).

We have also added a new definition for reviewing authority that clarifies who has authority to implement major NSR programs. Reviewing authority means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under §§ 51.165 and 51.166, or the Administrator in the case of EPA-implemented permit programs under § 52.21.

7. Enforcement

As noted above, today we are taking final action on five changes to the NSR program that create alternative means of determining NSR applicability for projects that begin actual construction after these provisions become effective in your jurisdiction. If you are subsequently determined not to have met any of the obligations of these new alternatives (for example, failure to meet emissions or applicability limits, properly project emissions, and/or properly implement the PCP Exclusion or Clean Unit Test), you will be subject to any applicable enforcement provisions (including the possibility of citizens' suits) under the applicable sections of the Act. Sanctions for violations of these provisions may include monetary penalties of up to $27,500 per day of violation, as well as the possibility of injunctive relief, which may include the requirement to install air pollution controls.

8. Enforceability

This rule uses several terms related to enforceability of particular provisions. A requirement is "legally enforceable" if some authority has the right to enforce the restriction. Practical enforceability for a source-specific permit will be achieved if the permit's provisions specify: (1) A technically-accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance, including appropriate monitoring, recordkeeping, and reporting. For rules and general permits that apply to categories of sources, practicable enforceability additionally requires that the provisions: (1) Identify the types or categories of sources that are covered by the rule; (2) where coverage is optional, provide for notice to the permitting authority of the source's election to be covered by the rule; and (3) specify the enforcement consequences relevant to the rule.[7,8] ''Enforceable as a practical matter'' will be achieved if a requirement is both legally and practically enforceable.

Note that we continue to require offsets to be federally enforceable. ''Federal enforceability'' means that not only is a requirement practically enforceable, as described above, but in addition, ''EPA must have a direct right to enforce restrictions and limitations imposed on a source to limit its exposure to Act programs.''[9] Also note that, for computing baseline actual emissions for use in determining major NSR applicability or for establishing a PAL, you must consider ''legally enforceable'' requirements. A requirement will be legally enforceable if the Administrator, State, local or tribal air pollution control agency has the authority to enforce the requirement irrespective of its practical enforceability.

In our existing regulations that are unamended by today's action, the term ''federally enforceability'' still appears. In 1995, the court in *Chemical Manufacturers Ass'n* v. *EPA* remanded the definition of PTE in the major NSR program to EPA. No. 89–1514 (D.C. Cir. Sept. 150 1995). Because the court vacated the requirements in the nationwide rules, the term federal enforceability as it relates to PTE is not in effect (pending final rule making by the Agency) in the Federal rules. The decision, however, did not address the term ''federally enforceable'' as used in SIPs, because that issue was not before the court.

II. Revisions to the Method for Determining Whether a Proposed Modification Results in a Significant Emissions Increase

A. Introduction

Today we are finalizing two sets of amendments to our existing major NSR regulations that provide another way in which you may calculate emissions increases to determine whether certain types of physical changes or changes in the method of operation (physical or operational changes) of an existing emissions unit trigger the major NSR requirements.[10] The first set of amendments relates to the way in which you will determine your baseline actual emissions for such emissions units in accordance with a new definition of ''baseline actual emissions.'' *See,* for example, new § 52.21(b)(48). We will be allowing you to use any consecutive 24-month period during the 10-year period prior to the change to determine your baseline actual emissions for existing emissions units (other than EUSGUs). The second set of amendments replaces the existing actual-to-potential and actual-to-representative-actual-annual emissions applicability tests for existing emissions units (including EUSGUs) with an actual-to-projected-actual applicability test for determining if a physical or operational change will result in an emissions increase at such units. (Notwithstanding this new test, the actual-to-potential methodology is still available at your option under the new applicability tests.) The new procedure for determining your pre-change baseline actual emissions will not apply to EUSGUs.[11] Instead, for EUSGUs we are retaining the existing procedures for determining the baseline actual emissions.[12] *See,* for example, existing § 52.21(b)(33). We are also affirming our current method used for calculating the baseline actual emissions for EUSGUs (allowing any consecutive 2 years in the past 5 years, or another more representative period) by codifying it in the NSR regulations. *See,* for example, new § 52.21(b)(48).

For existing emissions units other than EUSGUs, the changes we are making to the method for calculating a unit's baseline actual emissions will apply only for the following three purposes.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test.
- For netting, to determine the pre-change baseline actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period.
- For PALs, to establish the PAL emissions cap.

Today's new procedures for calculating baseline actual emissions and for the actual-to-projected-actual applicability test should not be used when determining a source's actual emissions on a particular date as may be used for other NSR-related requirements. Such requirements include, but are not limited to, air quality impacts analyses (for example, compliance with NAAQS, PSD increments, and AQRVs) and computing the required amount of emissions offsets. For each of these requirements, the existing definition of ''actual emissions'' continues to apply. This is discussed in greater detail in section II.D.9.

We believe that these changes will greatly improve the major NSR program by responding to industry concerns with our existing methodology without compromising air quality. One common complaint about the current emissions baseline process is that you have a limited ability to consider the operational fluctuations associated with normal business cycles when establishing baseline actual emissions unless your reviewing authority agrees that another period is ''more representative of normal source

[7] See memorandum, ''Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit,'' signed by John Seitz and Robert Van Heuvelen, Jan. 22, 1996 at 5–6 and Attachment 4, available on the Web as *http://www.epa.gov/rgytgrnj/programs/artd/air/title5/t5memos/pottoemi.pdf.* More detailed guidance on practical enforceability is contained in the memorandum.

[8] The Agency has frequently used the term ''practicably enforceable'' and ''practical enforceability,'' interchangeably. There is no difference in the meaning of these terms.

[9] *See* generally memorandum, ''Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act,'' signed by John Seitz and Robert Van Heuvelen, Jan. 25, 1995, at 2–3.

[10] By definition, the modification of an existing source is potentially subject to major NSR only if that existing source is ''major.'' In addition, when an existing ''minor'' source makes a physical or operational change that by itself is major, that change constitutes a major stationary source that is subject to major NSR. *See*, for example, § 52.21(b)(1)(*c*).

[11] For NSR purposes, the definition of ''electric utility steam generating unit'' means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility. See, for example, § 52.21(b)(31). Reference in this notice to utility units is meant to include all emissions units covered by this definition.

[12] We promulgated special applicability rules for physical and operational changes at EUSGUs in 1992. *See* 57 FR 32314 (July 21, 1992).

operation.'' [13] By extending the time period from which you may establish your baseline actual emissions, the new procedures should reflect the emissions levels that occur during a normal business cycle, without requiring you to demonstrate to your reviewing authority that another period is ''more representative of normal source operations.''

Commenters also believe that the current methodology requires many changes made to existing equipment to go through major NSR, without taking into account operating history, even when such changes will not result in increased pollution to the environment. Our new applicability requirements address these commenters' concerns and will focus limited resources more effectively.

We are also modifying the way you may determine whether emissions at existing units (including EUSGUs) will increase, by allowing you to use projected actual emissions for purposes of this determination. Under this approach, in circumstances where there is a reasonable possibility that a project that is not part of a major modification may result in a significant increase of a regulated NSR pollutant, before beginning actual construction, you may choose to make and record a projection of post-change emissions of that pollutant from changed units.[14]

To make this projection, you must use the maximum annual rate at which the changed units are projected to emit the pollutant in any of the 5 calendar years following the time the unit resumes regular operations after the project (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). You then use these projections to calculate whether the project will result in a significant emissions increase. In making this calculation, you could exclude any emissions that the unit could have accommodated before the change and that are unrelated to the project. You could also exclude emissions resulting from increased utilization due to demand growth that the unit could have accommodated before the change.

With respect to the covered changes, if you use this procedure, you are required to track post-change annual emissions of the units in tpy for the next 5 years (or 10 years if the project increases the unit's design capacity or potential to emit the regulated NSR pollutant). At the end of each year, if post-change annual emissions exceed the baseline actual emissions by a significant amount, and differ from your projections, you must submit a report to the reviewing authority with that information within 60 days after the end of the year.

Instead of relying on projected actual emissions, you may instead elect to use the unit's PTE, in tpy. In that case, you need not track or report post-change emissions.

We are also revising the procedures for projecting future emissions for EUSGUs to conform with these new procedures and consolidate the EUSGU and non-EUSGU procedures into a single set of provisions. As a result of our 1992 rulemaking, EUSGUs have available to them a similar set of procedures. We believe the procedures we are implementing for other units represent a sensible refinement of the rules we promulgated in 1992 and that we should make these procedures available to all existing units. We do, however, impose two requirements on EUSGUs beyond those we impose on other units. First, with respect to covered projects, EUSGUs that project post-change emissions will have to submit a copy of their projections to their reviewing authority before beginning actual construction. You will not be required to obtain any kind of determination from the reviewing authority before proceeding with construction. Second, we are requiring that if you project post-change emissions for your EUSGUs, you must send a copy of your tracked emissions to your reviewing authority, without regard to whether these emissions have increased by a significant amount or exceed your projections. The effect of this consolidation is that we make minor changes to the existing procedures for EUSGUs. For example, you must project emissions for EUSGUs on a 12-month basis, rather than the current approach of projecting average annual emissions for the 2 years immediately following the change. Also, you need only make and report a projection for EUSGUs when there is a reasonable possibility that the given project may result in a significant emissions increase.

By allowing you to use today's new version of the actual-to-projected-actual applicability test to evaluate modified existing emissions units, we expect that fewer projects will trigger the major NSR permitting requirements. Nonetheless, we believe that the environment will not be adversely affected by these changes and in some respects will benefit from these changes. The new test will remove disincentives that discourage sources from making the types of changes that improve operating efficiency, implement pollution prevention projects, and result in other environmentally beneficial changes. Moreover, the end result is that State and local reviewing authorities can appropriately focus their limited resources on those activities that could cause real and significant increases in pollution.

In addition, today's changes provide benefits to the public and the environment through the improved recordkeeping and reporting requirements as discussed above. We believe that these added recordkeeping and reporting measures will provide the information necessary for reviewing authorities to assure that such changes are made consistent with the CAA requirements. The new rule also does not affect the way in which a source's ambient air quality impacts are evaluated. Altogether, we believe that today's regulatory amendments focus on the types of changes occurring at existing emissions units that are more likely to result in significant contributions to air pollution.

B. What We Proposed and How Today's Action Compares

1. July 23, 1996 Notice of Proposed Rulemaking (NPRM)

In 1996, we proposed to amend the NSR rules to allow States to use, among other things, a new test as an alternative to the actual-to-potential test for determining the applicability of the NSR requirements when you wish to make modifications at an existing major stationary source. The proposed test was intended to apply exclusively to modifications of existing emissions units at major stationary sources—not to new emissions units. As described more completely below, the proposed test involved changes to the procedures for calculating an emissions unit's pre-change (baseline) actual emissions and post-change (future) actual emissions. The method would have also required you to monitor and report future emissions from certain modified

[13] The definition of ''actual emissions'' requires that a unit's actual emissions be based on a consecutive 24-month period immediately preceding the particular change. Also, however, it directs the reviewing authority to allow the use of another time period upon a determination that it is more representative. This procedure continues to be appropriate under the pre-existing regulation and for other NSR purposes, such as determining a source's ambient impact against the PSD increments, and we continue to require its use for such purposes.

[14] Note that we plan, in the near future, to issue a Notice of Proposed Rulemaking that will address the issue of ''debottlenecking.'' In today's rulemaking, we do not intend to change current requirements related to ''debottlenecking.'' Use of the term ''changed unit'' should not be interpreted as a change to those requirements.

emissions units, based on the monitoring and reporting requirements adopted under the WEPCO amendments.

Baseline actual emissions. In our 1996 NPRM, we proposed to change the definition of baseline emissions from the average annual rate of actual emissions during the 2-year period preceding the date of the modification to the annual rate associated with the highest level of utilization from any consecutive 12-month period during the 10-year period preceding the date of the modification, adjusted for any more stringent limits that may have been imposed since the end of the 12-month period selected. The proposed method was intended to be used for calculating baseline actual emissions for any existing emissions unit, including EUSGUs, by replacing both the original method (that was part of the actual-to-potential test) and the 2-in-5-years method (as adopted under the WEPCO for modified EUSGUs).

As indicated above, the proposed procedure also would have required you to take into account any legally enforceable constraints imposed on the facility since the selected 12-month time frame, and currently in effect. Thus, you would generally have been required to calculate the modified emissions unit's baseline actual emissions by using the appropriate utilization level from the selected 12-month period, in combination with the emissions unit's current enforceable emission factors. Such enforceable emission factors would have included current Federal and State limits, such as RACT (Reasonably Available Control Technology), MACT (Maximum Achievable Control Technology), BACT, LAER, and New Source Performance Standards (NSPS), as well as enforceable limits resulting from any voluntary reductions you may have taken (for example, for netting, offsets, or Emission Reduction Credits (ERCs)). Also, you would have had to consider any operational constraints that are enforceable, such as production limits, fuel use limits, or limits to the number of hours per day or days per year at which the unit modified, or affected by such modification, could operate.

Finally, we indicated that it was not our intent to extend the 5-year contemporaneous period (for considering creditable emissions increases and decreases as part of the netting calculus), even if we established a 10-year baseline look back period.

Post-change actual emissions. In the 1996 proposal, we proposed to extend the availability of the actual-to-future-actual emissions method, established under the WEPCO amendments exclusively for EUSGUs, to predict the future actual emissions from any emissions unit undergoing a physical or operational change. Thus, we proposed extending availability of the definition of ''representative actual annual emissions'' to all emissions units undergoing a physical or operational change. This definition would have provided the basis for you to project an emissions unit's future actual emissions, excluding any emissions increases caused by demand growth or other independent factors, when determining whether the change at issue will increase emissions over the baseline levels.[15]

The proposal also retained the WEPCO provision requiring that, for any modified emissions unit using the actual-to-future-actual test, you must submit annually for 5 years after the change sufficient records to demonstrate that the change has not resulted in a significant emissions increase over the baseline levels. As a safeguard, the WEPCO rule also provides that this tracking period could be extended to 10 years when the reviewing authority is concerned that the first 5 years will not be representative of normal source operation. We sought comments on numerous issues, including whether any changes should be made to the 5-year tracking requirement or to the demand growth exclusion in the event that we decided to broaden use of the actual-to-future-actual test for modifications to any existing emissions unit.

2. July 24, 1998 Notice of Availability

In 1998, we announced that comments received on the 1996 proposal and changed circumstances had caused us to ask whether we should reconsider some of the aspects of the proposed changes to the ''major modification'' applicability test. The 1998 NOA set forth for public comment an additional applicability test. In brief, the alternative presented for additional comment would have: (1) Retained the actual-to-future-actual test for EUSGUs and applied it to all source categories; (2) made binding for a 10-year period the emissions levels used in projecting future actual emissions following the modification for all source categories; and (3) eliminated the demand growth exclusion for calculating a modified emissions unit's future actual emissions.

Consistent with the 1996 NPRM, this alternative methodology would have applied to any existing emissions unit at a major stationary source for which you might plan a non-routine physical or operational change. The methodology would have required you first to determine which emissions units were being changed, or were affected by the change, then to calculate those units' baseline actual emissions based on the highest consecutive 12 months of source operation during the past 10 years, adjusted to reflect current emission factors.

The second step involved the forecast of future emissions resulting from the physical or operational change. Under this calculation of future actual emissions, one would not have been allowed to exclude predicted capacity utilization increases that were due to demand growth. If the difference between the pre-change and post-change actual emissions equaled or exceeded the significant emissions rate defined for a particular pollutant, major NSR would have been triggered (unless you took enforceable limits to keep the increase below significant levels or were otherwise able to net out of review using creditable, contemporaneous emissions increases and decreases occurring at your facility). If the difference between baseline and future actual emissions did not exceed the applicable significant emissions rate, your facility would not be subject to major NSR, but you would have been required to accept a temporary emissions cap based on the predicted future actual emissions for each affected pollutant at the emissions units being modified or affected by the modification.

The temporary cap would have become an enforceable condition of a preconstruction permit. Also, the sole purpose of the temporary cap would have been to make sure that the physical or operational change did not result in a significant emissions increase, and the cap would have applied to those emissions units for at least 10 years after the changes were completed. You would also have been required to supply information annually to demonstrate that the future actual emissions did not exceed the applicable emissions caps during the 10-year period following the modification.

3. Summary of Major Changes in the Final Rule

Today's action amends the existing NSR regulations to provide you with a common applicability test for all existing emissions units—the actual-to-projected-actual applicability test. This test has changed in some ways from both the 1996 NPRM and the 1998 NOA. As described in greater detail in sections

[15] This method, as well as the WEPCO amendments as a whole, was limited to modifications of existing EUSGUs and did not apply to the addition of a new emissions unit or the replacement of an existing unit.

II.C and II.D below, the key features of the methodology are as follows.

• If you are an existing emissions unit (other than an EUSGU), you will determine the pre-change (baseline) actual emissions by calculating an average annual emissions rate, in tpy, using any consecutive 24 months during the 10-year period immediately preceding the change. This rate must be adjusted downward to reflect any legally enforceable emission limitations imposed after the selected baseline period.

• We are codifying the ''2-in-5-years'' presumption for calculating the baseline actual emissions for EUSGUs.

• If you are an existing emissions unit (including EUSGUs), you will estimate post-change emissions (projected actual emissions), in tpy, to reflect any increase in annual emissions that may result from the proposed change. You should exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the baseline period and that is also unrelated to the particular project, including any increased utilization due to product demand growth. You must make the projection before you begin actual construction. When using this method, you must record the projection and certain other information in circumstances where there is a reasonable possibility that a change may result in a significant emissions increase. In addition, EUSGUs must send a copy of the projections and other information to your reviewing authority before beginning actual construction.

• If, for a project at an existing emissions unit (other than an EUSGU) at a major stationary source, you elect to project your post-change emissions, we are also requiring you to maintain information on these emissions, for 5 years following a physical or operational change, or in some cases for 10 years depending on the nature of the change. If your annual emissions exceed the baseline actual emissions by a significant amount and also exceed your projection, you must report this information to your reviewing authority within 60 days after the end of the year.

• If you project post-change emissions for EUSGUs, you must report these emissions to your reviewing authority within 60 days after the end of the year without regard to whether such emissions exceed the baseline actual emissions or projected actual emissions for a period of 5 years (or in some cases 10 years, depending on the nature of the change).

• Instead of projecting your post-change emissions, for all existing emissions units you may instead project post-change emissions on the basis of each unit's post-change PTE. If you use this method, you need not record your projections or track or report post-change emissions.

As discussed earlier, our prior regulations provide that when your emissions unit, other than an EUSGU, ''has not begun normal operations, ''actual emissions equal the PTE of the unit. There have been considerable number issues raised with this approach. For example, using PTE as a measure of post-change emissions automatically attributes all possible emissions increases to the change. There are many cases, however, where this simply is not true. Moreover, when the actual-to-potential test is applied, it is automatically assumed that the emissions unit has not begun normal operations after the change period. In many such cases, however, the changed unit as a practical matter will function essentially as it did before the change. We are, therefore, allowing all existing emissions units to use an actual-to-projected-actual applicability test. Accordingly, we are generally eliminating the term ''begun normal operations'' from the determination of whether a change results in a significant emissions increase.[16]

For essentially the same reasons, while our 1992 rules did not authorize use of projections in evaluating whether replacement of an existing emissions unit (which we understood to require application of the NSPS 50 percent cost threshold) constitutes a major modification, upon reflection we have decided this exception to the availability of the actual-to-projected-actual applicability test is also unnecessary. In our 1980 rulemaking, we decided against applying PSD to ''reconstruction,'' even of entire sources, on the grounds that, as to existing sources that would not otherwise be subjected to PSD review as a major modification (*i.e.*, such source would not cause a significant net emissions increase), changes that had no emission consequences should not be subject to PSD regardless of their magnitude.[17]

In addition, we now believe that, as with modified units, the fact that replacement units are replacing similar units with a record of historical operational data provides sufficient reasons to believe that a projection of future actual emissions can be sufficiently reliable that an up-front emissions cap based on PTE is unnecessary. In other words, a source replacing a unit should be able to adequately project and track emissions for the replacement unit based, in part, on the operating history of the replaced unit. In contrast, sources adding ''new'' units that do not qualify as replacement units must project that the future emissions of the new unit equal its PTE, effectively applying the ''actual-to-potential'' test because there is no relevant historical data that could be used to establish an actual emissions baseline or projection of future actual emissions for such new units.

For these reasons, we have eliminated the requirement that replaced or reconstructed units be evaluated as to whether they constitute major modifications on an actual-to-potential basis. Instead, you may compare an emission unit's baseline actual emissions with your projected actual emission in measuring whether the replacement or reconstruction has resulted in a significant emissions increase. You must treat these emissions units as modifications only if the replacement or reconstruction of the unit results in a signficant increase so measured.[18]

[16] We do make use of the term ''resumes regular operations'' (as opposed to ''normal operations'') in the final rule, but that term has a very different meaning and we are using it for an entirely different purpose. Specifically, we are not using the term for purposes of determining whether a change results in a significant emissions increase. Rather, we use it only to identify the date on which the owner or operator must begin tracking emissions of changed units when using the actual-to-projected-actual method.

[17] The 1980 rulemaking also discussed that ''reconstruction'' would have only been applied on a plantwide basis and EPA believed that there would be few instances of plantwide reconstructions.

[18] For simplicity, we state this rule without addressing whether the replacement or reconstruction has resulted in a significant net emissions increase, but under our two-step approach for evaluating whether a change constitutes a major modification, a significant net emissions increase would of course also be required. We have also retained the term ''representative of normal operations'' in the context of an EUSGU's option to seek use of a different baseline period, but there the question whether to seek such use is at the source's option, obviating many of the difficulties with it in other contexts.

C. Changes to the Procedures for Calculating the Pre-Change Baseline Actual Emissions for Existing Emissions Units Other Than EUSGUs

1. Under Today's New Requirements, How Should I Calculate the Pre-Change Baseline Actual Emissions for an Existing Emissions Unit That Is Not an EUSGU?

When you calculate the baseline actual emissions for an existing emissions unit (other than an EUSGU), you may select any consecutive 24 months of source operation within the past 10 years. Using the relevant source records for that 24-month period, including such information as the utilization rate of the equipment, fuels and raw materials used in the operation of the equipment, and applicable emission factors, you must be able to calculate an average annual emissions rate, in tpy, for each pollutant emitted by the emissions unit that is modified, or is affected by the modification.

The new requirements prohibit you from counting as part of the baseline actual emissions any pollution levels that are not allowed under any legally enforceable limitations and that apply at the time of the project. Therefore, you must identify the most current legally enforceable limits on your emissions unit. If these legally enforceable emission limitations and operating restrictions are more stringent than those that applied during the 24-month period, you must adjust downward the average annual emissions rate that you calculated from the consecutive 24-month period to reflect these current restrictions. (*See* section II.C.5 of this preamble for further discussion of the adjustment that you may need to make.)

In summary, when the average annual emissions rate that you originally calculated is still legally achievable (see discussion below), then your baseline actual emissions will be the same as the average annual emissions rate calculated from the 24-month period. If it is not, you must adjust it downward so that it does not reflect emissions that are no longer legally allowed.

2. Can Existing Emissions Units (Other Than EUSGUs) Still Use a ''More Representative Time Period'' for Selecting the Baseline Actual Emissions?

No, under today's new requirements neither you nor your reviewing authority will have the authority to select another period of time from which to calculate your baseline actual emissions. You must select a 24-month period within the 10-year period before the physical or operational change.

3. From What Point in Time Is the 10-Year Look Back Measured?

If you believe that you will need either a major or minor NSR permit to proceed with your proposed physical or operational change, then you must use the 10-year period immediately preceding the date on which you submit a complete permit application. If, however, you believe that the physical or operational change(s) you plan to make will not result in either a significant emissions increase from the project or a significant net emissions increase at your major stationary source (that is, your project will not be a major modification), and you are not otherwise required to obtain a minor NSR permit before making such change, then you must use the 10-year period that immediately precedes the date on which you begin actual construction of the physical or operational change.

4. What if, for an Existing Emissions Unit (Other Than an EUSGU), I Do Not Have Adequate Documentation for Its Operation for the Past 10 Years?

Your ability to use the full 10 years of the look back period will depend upon the availability of relevant data for the consecutive 24-month period you wish to select. The data must adequately describe the operation and associated pollution levels for the emissions units being changed. If you do not have the data necessary to determine the units' actual emission factors, utilization rate, and other relevant information needed to accurately calculate your average annual emissions rate during that period of time, then you must select another consecutive 24-month period within the 10-year look back period for which you have adequate data.

5. For an Existing Unit (Other Than EUSGUs), When Must I Adjust My Calculation of the Pre-Change Baseline Actual Emissions?

Today's amendments require you to adjust the average annual emissions rate derived from the selected 24-month period under certain circumstances. Specifically, you must adjust downward this average annual rate if any legally enforceable emission limitations, including but not limited to any State or Federal requirements such as RACT, BACT, LAER, NSPS, and National Emission Standards for Hazardous Air Pollutants (NESHAP), restrict the emissions unit's ability to emit a particular pollutant or to operate at levels that existed during the selected 24-month period from which you calculate the average annual emissions rate. For example, assume that during the selected consecutive 24-month period you burned fuel oil and you were subjected to a sulfur limit of 2 percent sulfur (by weight). Today, you are only allowed to burn fuel oil with a sulfur content of 0.5 percent or less. Consequently, you would be required to adjust your preliminary calculation of baseline actual emissions for sulfur dioxide (SO_2) (that is, substitute the lower sulfur limit into the emissions calculation, yielding a 75 percent reduction in the emissions rate from the initial calculation) to reflect the current restriction allowing only 0.5 percent sulfur in fuel oil. The original average annual utilization rate would not be adjusted unless a more stringent legally enforceable operational limitation has since been imposed that restricts that rate.

You must also adjust for legally enforceable emission limitations you may have voluntarily agreed to, such as limits you may have taken in your permit for netting, emissions offsets, or the creation of ERCs. Also, you must adjust your emissions from the 24-month period if a raw material you used during the baseline period is now prohibited. For example, you may have used a paint with a high solvent concentration during a portion of the consecutive 24-month period. Today, you are prohibited from using that particular paint. You must then adjust your emissions rate to reflect the raw material restriction.

6. How Should I Calculate the Baseline Actual Emissions for Emissions Units (Other Than EUSGUs) That Use Multiple Fuels or Raw Materials?

For an emissions unit that is capable of burning more than one type of fuel, you must relate the current emission factors to the fuel or fuels that were actually used during the selected 24-month period. For example, when calculating the baseline actual emissions for an emissions unit that burned natural gas for a portion of the 24-month period and fuel oil for the remainder, you must retain that fuel apportionment (for example, natural gas to fuel oil ratio), but you must also use the current legally enforceable emission factors for natural gas and fuel oil, respectively, to calculate the baseline actual emissions. If, however, you are no longer allowed or able to use one of those fuel types, then you must make your calculations assuming use of the currently allowed fuel for the entire 24-month period. You must use the same approach for emissions units that use multiple feedstock or raw materials, which may vary in use during the unit's ongoing production process.

7. How Should I Calculate the Baseline Actual Emissions for Construction Projects That Involve Multiple Units?

Today's new requirements require that you select the same single consecutive 24-month period within the 10-year look back period to calculate the baseline actual emissions for all existing emissions units that will be changed. *See,* for example, new § 52.21(b)(48)(ii)(*e*). The result will be that the baseline actual emissions for each affected pollutant will be based on the same consecutive 24-month period as well.

You will have the option to select the single 24-month period that best represents the collective level of operation (and emissions) for your existing emissions units.

If a particular existing emissions unit did not yet exist during the 24-month period you select to calculate the baseline actual emissions, you must count that emissions unit's emissions rate as zero for that full period of time. If an emissions unit operated for only a portion of the particular 24-month period that you select, you must calculate its average annual emissions rate using an emissions rate of zero for that portion of time when the unit was not in operation.

For new emissions units (a unit that has existed for less than 2 years) that will be changed by the project, the baseline actual emissions rate is zero if you have not yet begun operation of the unit, and is equal to the unit's PTE once it has begun to operate.

8. Am I Able To Apply Today's Changes for Calculating the Baseline Actual Emissions to Other Major NSR Requirements?

No, as stated in section II.A, you are only allowed to use the new baseline methodology in today's rule for three specific purposes involving existing emissions units as follows.

- For modifications, to determine a modified unit's pre-change baseline actual emissions as part of the new actual-to-projected-actual applicability test
- For netting, to determine the pre-change actual emissions of an emissions unit that underwent a physical or operational change within the contemporaneous period. You may select separate baseline periods for each contemporaneous increase or decrease.
- For PALs, to establish the PAL level.

If you determine that the modification of your source is a major modification, you must revert to using the existing definition of ''actual emissions'' to determine your source's actual emissions on a particular date to satisfy all other NSR permitting requirements, including any air quality analyses (for example, compliance with NAAQS, PSD increments, AQRVs) and the amount of emissions offsets required.

For example, when you must determine your source's compliance with the PSD increments following a major modification, you must still use the allowable emissions from each emissions unit that is modified, or is affected by the modification. An existing source's contribution to the amount of increment consumed should be based on that source's actual emissions rate from the 2 years immediately preceding the date of the change, although the reviewing authority shall allow the use of another 2-year period if it determines that such period is more representative of that source's normal operation. *See,* for example, § 52.21(b)(21)(ii).

Also, any determination of the amount of emissions offset that must be obtained by a major modification subject to the nonattainment NSR requirements under § 51.165(a) should be based on calculations using the existing definitions of ''actual emissions'' and ''allowable emissions.'' See new § 51.165(a)(3)(ii)(H).

D. The Actual-to-Projected-Actual Applicability Test for Physical or Operational Changes to Existing Emissions Units Including EUSGUs

1. How are post-change actual emissions calculated under today's revised rule?

Today, we are amending the major NSR rules to enable you to use an applicability test that is similar to the applicability test that currently applies to EUSGUs (that is, the actual-to-representative-actual-annual emissions test). The new test allows you to project the post-change emissions of all modified existing emissions units (including EUSGUs) in the same manner. That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in tpy, that reflects the maximum annual emissions rate that will occur during any one of the 5 (or in some circumstances 10) years immediately after the physical or operational change. The first year begins on the day the emissions unit resumes regular operation following the change and includes the 12 months after this date. This projection of the unit's annual emissions rate following the change is defined as the ''projected actual emissions'' (see, for example, § 52.21(b)(48)), and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24-month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the emissions unit's operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions unit's likely post-change capacity utilization. In calculating the projected actual emissions, you should consider both the expected and the highest projections of the business activity that you expect could be achieved and that are consistent with information your company publishes for business-related purposes such as a stockholder prospectus, or applications for business loans. From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. Once the appropriate subtractions have been made, the final value for the projected actual emissions, in tpy, is the value that you compare to the baseline actual emissions to determine whether your project will result in a significant emissions increase.

The adjustment to the projected actual emissions allows you to exclude from your projection only the amount of the emissions increase that is not related to the physical or operational change(s). In comparing your projected actual emissions to the units' baseline actual emissions, you only count emissions increases that will result from the project. For example, as with the electric utility industry, you may be able to attribute a portion of your emissions increase to a growth in demand for your product if you were able to achieve this higher level of production during the consecutive 24-month period you selected to establish the baseline actual emissions, and the increased demand for the product is unrelated to the change.

For Clean Units, if a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, then no emissions increase will occur.

For new units, however, you must continue to calculate post-change emissions on the basis of a unit's PTE.

2. Will My Projection of Projected Actual Emissions Become an Enforceable Emission Limitation as Suggested in the 1998 NOA?

No, we did not adopt such a requirement. If you have an existing emissions unit and your project results in an increase in annual emissions that exceeds the baseline actual emissions by a significant amount, and differs from your projection of post-change emissions that you were required to calculate and maintain records of, then you must report this increase to your reviewing authority within 60 days after the end of the year. Since modified EUSGUs are required to report their post-change annual emissions to the reviewing authority annually, any occurrence of a significant increase will be covered under that report for the affected calendar year. *See* section II.D.6 of this preamble for a more detailed discussion of the reporting requirements.

3. How Do I Determine How Long My Post-Change Emissions Will Be Tracked To Ensure That My Project Is Not a Major Modification?

Generally, your projected actual emissions must be tracked against your facility's post-change emissions for 5 years following resumption of regular operations whether you are an EUSGU or other type of existing emissions unit. We will presume that any increases that occur after 5 years are not associated with the physical or operational changes. However, you may be required to track emissions for a longer period of time under the following circumstances. If you are an existing emissions unit and one of the effects of your physical or operational change(s) is to increase a unit's design capacity or PTE, you must track your emissions for a period of 10 years after the completion of the project. This extended period allows for the possibility that you could end up using the increased capacity more than you projected and such use might lead to significant emissions increases.

4. What Are the Reporting and Recordkeeping Requirements for Projects?

Reporting and recordkeeping for a project is required when three criteria are met: (1) You elect to project post-change emissions rather than use PTE; (2) there is a reasonable possibility that the project will result in a significant emissions increase; and (3) the project will not constitute a major modification. In such circumstances, you must document and maintain a record of the following information: a description of the project; an identification of emissions units whose emissions could increase as a result of the project; the baseline actual emissions for each emissions unit; and your projected actual emissions, including any emissions excluded as unrelated to the change and the reason for the exclusion. In addition, if your project increase is significant, you must record your netting calculations if you use emissions reductions elsewhere at your major stationary source to conclude that the project is not a major modification. For covered projects, you must record this information before beginning actual construction. If you are an EUSGU, you must also send this information to your reviewing authority before beginning actual construction. Note, however, that if you chose to use potential emissions as your projection of post-change emissions, you are not required to maintain a record of this decision.

In addition, today's final rules require you to maintain emissions data for all emissions units that are changed by the project. You must maintain this information for 5 years, or 10 years if applicable. The information you must maintain may include continuous emissions monitoring data, operational levels, fuel usage data, source test results, or any other readily available information of sufficient accuracy for the purpose of determining an emissions unit's post-change emissions.

If you are an EUSGU, you must report this information to your reviewing authority within 60 days after the end of any year in which you are required to generate such information. Other existing units must report to the reviewing authority any increase in the post-change annual emissions rate when that rate: (1) Exceeds the baseline actual emissions by a significant amount, and (2) differs from the projection that was calculated before the change. See, for example, new § 52.21(r)(6)(iii).

In addition to the reporting requirements discussed above, you are also obligated to ensure that the necessary emissions information you are required to maintain is available for examination upon request by the reviewing authority or the general public.

5. How Do Today's Changes Affect the Netting Methodology for Existing Emissions Units (Other Than EUSGUs)?

If your calculations show that a significant emissions increase will result from a modification, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to "net out" of review, that is, show that the net emissions increase at the major stationary source will not be significant. The contemporaneous time period will not change under the Federal PSD program as a result of today's action. That is, creditable increases and decreases in emissions that have occurred between the date 5 years before construction of the particular change commences and the date the increase from that change occurs are contemporaneous. *See* § 52.21(b)(3)(ii). States will continue to have some discretion in defining "contemporaneous" for their own NSR programs.

Although we are not changing our definition of "contemporaneous," today's action allows existing emissions units (other than EUSGUs) to calculate the baseline actual emissions for each contemporaneous event using the 10-year look back period. That is, you can select any consecutive 24-month period during the 10-year period immediately preceding the change occurring in the contemporaneous period to determine the baseline actual emissions for each creditable emissions change. Generally, for each emissions unit at which a contemporaneous emissions change has occurred, you should use the 10-year look back period relevant to that change.[19] When evaluating emissions increases from multi-unit modifications, if more than one emissions unit was changed as part of a single project during the contemporaneous period, you may select a separate consecutive 24-month period to represent each emissions unit that is part of the project. In any case, the calculated baseline actual emissions for each emissions unit must be adjusted to reflect the most current emission limitations (including operational restrictions) applying to that unit. "Current" in the context of a contemporaneous emissions change refers to limitations on emissions and source operation that existed just prior to the date of the contemporaneous change.

E. Clarifying Changes to WEPCO Provisions for EUSGUs

The method you use to calculate the baseline actual emissions for an existing EUSGU to determine whether there is a

[19] Your ability to use the full 10 years for calculating any contemporaneous emissions change is contingent upon the availability of valid and sufficient source information for the selected 24-month period. *See,* for example, new § 52.21(b)(48)(ii)(*f*).

significant emissions increase from a physical or operational change at an EUSGU, and to determine whether a significant net emissions increase will occur at the major stationary source, will not change as a result of today's final rulemaking. The rule provides that for an existing EUSGU you may calculate the baseline actual emissions as the average annual emissions (tpy) of the emissions unit using any 2-year period out of the 5 years immediately preceding the modification. (This was set out as a presumption in the preamble for the 1992 WEPCO amendments.) This rule recognizes the ordinary variability in demand for electricity. *See,* for example, new § 52.21(b)(21)(ii).

For example, a cold winter or hot summer will result in high levels of demand while a relatively mild year will produce lower demand. By allowing a utility to use any consecutive 2 years within the past 5, the rule recognizes that electricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant. By allowing utilities to use as a baseline any consecutive 2 years in the last 5 years, these types of fluctuations in operations can be more realistically considered.

The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

In an August 6, 2001 letter,[20] we addressed the issue of whether combined cycle gas turbines (the gas turbines and waste heat recovery components) came within the definition of ''electric utility steam generating units'' for the purpose of determining whether such units are eligible to use the WEPCO ''applicability test.'' The letter concluded that ''steam generating units'' include not only electric utility plants with boilers, but also plants with combined cycle gas turbines if the combined cycle gas turbine systems supply more than one-third of their potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Consequently, qualifying combined cycle gas turbines must also use the 2-in-5-years baseline method.

Finally, today's rules provide the same method for EUSGUs that will exist for all other existing emissions units to project post-change emissions following a physical or operational change to a unit. In the 1996 proposal, we proposed a range of options for addressing the applicability of changes that are made to existing emissions units, including the option of extending the actual-to-future-actual test, then available only to utilities, to all source categories. While we have decided to leave the WEPCO rules intact in most respects, we believe that it is reasonable and appropriate to establish a consistent method for sources to use for projecting the post-change emissions that will result from a physical or operational change to an existing emissions unit. Therefore, under today's new rules, the current method of basing the projection on the 2 years following the change to an EUSGU is being replaced with the method available to all other existing units, under which you project a unit's post-change emissions as the maximum annual rate that the unit will emit in any one of the 5 years following resumption of regular operations.

F. The ''Hybrid'' Applicability Test for Projects Affecting Multiple Types of Emissions Units

1. When Does the Hybrid Applicability Test Apply to You?

The hybrid applicability test applies if you plan a project (or series of related projects) that will affect emissions units of two or more of the following types.

- Existing emissions units
- New emissions units
- Clean Units

2. How Do I Determine Whether My Project Will Result in a Significant Emissions Increase Under the Hybrid Test?

For the first two types of emissions units listed above that are affected by the project, calculate the emissions increase as we have discussed previously in this preamble. That is, use the actual-to-projected-actual applicability test for existing units and the actual-to-potential test for new emissions units.

Clean Units are discussed fully in section V of this preamble. If a given project can be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit status, no emissions increase shall be deemed to occur at that Clean Unit. If a given project would cause the emissions unit to lose its Clean Unit status, then the increase in emissions should be calculated as if the emissions unit is not a Clean Unit.

After you calculate the emissions increase for each relevant unit, total the increases across all the emissions units of all types. If this total emissions increase equals or exceeds the level defined as significant for the regulated NSR pollutant in question, the project will result in a significant emissions increase for that pollutant. You'll find the regulatory language for determining whether a project will result in a significant emissions increase at §§ 51.165(a)(2)(vii)(D), 51.166(a)(7)(vi)(*d*), and 52.21(a)(2)(vi)(*d*).

In section II.C.8 of this preamble, we indicate that the baseline actual emissions for all units that are not EUSGUs that are changed by a project must be calculated based on the same consecutive 24-month period within the previous 10 years. The same principle applies under the hybrid test, but it can be slightly more complicated if both EUSGUs and non-EUSGUs are involved. In this case, you must use the same baseline period for all emissions units affected by the project. This baseline period must be selected so as to meet the requirements for both EUSGUs and non-EUSGUs. Thus, you must select a 2-year period out of the previous 5 years for your baseline period, as required for EUSGUs (and within the requirements for non-EUSGUs). If you wish to use another period that you believe is more representative (as allowed for EUSGUs), the entire period must fall within the previous 10 years (as required for non-EUSGUs).

3. How Do I Determine the Net Emissions Increase From My Project Under the Hybrid Test?

If you conclude that a significant emissions increase will result from the proposed project, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to ''net out'' of review, that is, show that the net emissions increase at the major stationary source will not be significant. The netting analysis is carried out under the hybrid test just as it is under the other applicability tests. Refer to section II.D.7 of this preamble for a discussion of netting methodology.

G. Legal Basis for Today's Action

The Act defines modification for the purposes of PSD and nonattainment NSR through cross-reference to the NSPS definition of ''modification.'' The NSPS definition states that a modification ''means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air

[20] Letter from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Patrick M. Raher, August 6, 2001.

pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' CAA section 111(a)(4), 42 U.S.C. 7411(a)(4). The Act is silent, however, on the issue of how one is to determine whether a physical or operational change increases the amount of any air pollutant emitted by the source.

Accordingly, EPA is exercising its discretion in interpreting and providing clarity to this issue. We believe that the rules set forth today are ''a permissible construction of the statute.'' *Chevron U.S.A., Inc.* v. *NRDC,* 467 U.S. 843–4 (1984). The reviewing court should defer to it. *Id.* at 837.

In the NSPS program, we determine whether there has been an ''increase in any air pollutant emitted'' by the source by comparing its maximum hourly achievable emissions before and after the change. EPA and the courts have recognized, however, that the NSR programs and the NSPS programs have different goals,[21] and thus, we have utilized different emissions tests in the NSR programs. Prior to today, the regulations applied an actual-to-future-actual applicability test for EUSGUs and an actual-to-potential applicability test for all other emissions units. Today, we are establishing a new applicability test for calculating emissions increases for ''Clean Units'' and an actual-to-projected-actual applicability test for all other emissions units. We believe that establishing an actual-to-projected-actual applicability test for all emissions units is a reasonable interpretation of the phrase ''increase of any pollutant emitted.''[22]

H. Response to Comments and Rationale for Today's Actions

We received numerous comments on our proposed rule regarding the calculation of the baseline actual emissions and the actual-to-future-actual test. Some of the significant comments and our responses to them are provided below. A complete set of comments and our responses can be found in the Technical Support Document located in the docket for this rulemaking.

1. Why Are We Extending the Look Back Period for Determining the Baseline Actual Emissions to 10 Years?

Most commenters generally support our proposal to allow owners and operators to use a 10-year look back period to determine the baseline actual emissions for modifications at any existing emissions unit. Commenters have various reasons for supporting or opposing the proposed approach. Many supporters agree that extending the baseline look back period to 10 years would simplify current regulations and provide certainty to sources who otherwise would have to demonstrate to the reviewing authority that a period other than the 2 years immediately preceding the proposed change was more representative of normal source operation. Some commenters support the proposal because it would prevent the perceived confiscation of underused capacity at sources that have had low utilization rates for an extended period. These commenters agree that a 10-year look back period is more likely to afford a source a baseline actual emissions calculation that best reflects representative source operating conditions and would also account for fluctuations in the business cycle.

Some commenters criticize the proposed 10-year look back period as being too long. These commenters recommend either a 5-year or 2-year look back period. One of these commenters states that the 10-year look back creates the opportunity for a source to increase production to the 10-year maximum, and prevents the State or local air regulators from addressing the increase in emissions. Thus, the commenter believes that sources would be allowed to use historic emissions levels that are higher than current levels to establish the baseline actual emissions. Some commenters add that the proposed change would not reduce program complexity.

Some commenters believe that instead of extending the period for establishing baseline actual emissions, the test for establishing modifications should be changed. According to the commenters, the problem is not that the current system does not go back far enough to set a fair actual emissions baseline, but that the methodology does not account for the fact that most emissions units are operating at an activity level much lower than the allowed activity level. The commenters believe that many of the real problems associated with the current major modification applicability test would be eliminated if the procedure was modified in an equitable manner.

A commenter also adds that EPA may also want to include provisions that prevent a source from applying the new definition of actual emissions in a way that would retroactively enable the source to reverse a previous major modification determination and to eliminate any emissions reduction previously required for that major modification.

We continue to believe that it is reasonable and appropriate to adopt the new method for establishing a modified unit's baseline actual emissions. It is important to understand the difference between the purpose of the new procedure, which uses the 10-year look back, and the existing procedure under the pre-existing definition of ''actual emissions'' at § 52.21(b)(21(ii), which generally requires the use of an average annual emissions rate based on the 2-year period immediately preceding a particular date. The latter procedure is designed to estimate a source's actual emissions at a particular time and continues to be appropriate for such things as estimating a source's impact on air quality for PSD increment consumption.

On the other hand, the new baseline procedure is specifically designed to allow a source to consider a full business cycle in determining whether there will be an emissions increase from a physical or operational change. Generally, a source's operations over a business cycle cover a range of operating (and emissions) levels—not simply a single level of utilization. The new procedure recognizes that market fluctuations are a normal occurrence in most industries, and that a source's operating level (and emissions) does not remain constant throughout a source's business cycle. The use of a 24-month period within the past 10 years to establish an average annual rate is intended to adjust for unusually high short-term peaks in utilization.

Consequently, the new procedure ensures that a source seeking to make changes at its facility at a time when utilization may not be at its highest can use a normal business cycle baseline by allowing the source to identify capacity actually used in order to determine an average annual emissions rate from which to calculate any projected actual emissions resulting from the change.

With respect to the commenters' general concerns that a 10-year look back period is too long, we sought to better understand what time period best represents an industry's normal business cycle. Therefore, we contracted for a study of several industries in 1997.[23] This study found that, for the

[21] See, for example, WEPCO Rule, 57 FR 32316 (''fundamental distinctions between the technology-based provisions of NSPS and the air quality-based provisions of NSR''). See also *ASARCO Inc.* v. *EPA,* 578 F.2d 319 (D.C. Cir. 1978).

[22] The explanation of the applicability test for ''Clean Units'' is discussed in section V.

[23] ''Business Cycles in Major Emitting Source Industries.'' Eastern Research Group; September 25, 1997. This study examined the business fluctuations for nine source categories described as CAA major emitting sources. Industry business cycles were examined using industry output data

Continued

industries analyzed, business cycles differ markedly by industry, and may vary greatly both in duration and intensity even within a particular industry. Nevertheless, we concluded from the study that 10 years of data is reasonable to capture an entire industry cycle. Comments from various industries support a conclusion that a 10-year look back period is a fair and representative time frame for encompassing a source's normal business cycle.

We believe that the use of a 10-year look back period will help provide certainty to the process and eliminate the ambiguity and confusion that occurred when an applicant and the reviewing authority disagreed on what time frame provides the period most representative of normal source operation. The new requirements also provide certainty to the look back period, since there is no opportunity to select another period of time outside this 10-year period. (See additional discussion in section II.E.2.) In addition, we have placed certain restrictions on when the full 10-year look back period may be used. (*See* section II.E.3.)

With regard to the concern that industry may try to apply the new requirements retroactively to undo current restrictions on existing sources, we want to reiterate that the new procedures do not apply retroactively to existing NSR permits or changes that sources have made in the past. Prior applicability determinations on major modifications and the control requirements that currently apply to sources remain valid and enforceable and have to be adjusted for in the calculation of baseline actual emissions. However, as part of the transition process for implementing the new provisions, we do intend to allow permit applicants to withdraw any permit applications submitted for review under the part 52 Federal PSD permit program so that they may re-evaluate their projects in light of the new requirements. States may allow for the same type of transition process under their own NSR programs.

Finally, we considered whether we should change the length of the look back period for EUSGUs for establishing the actual emissions baseline period to be consistent with the 10-year look back period we are adopting for other existing emissions units. The data we collected to support the 1992 rule changes show that allowing EUSGUs to use any 2-year period out of the preceding 5 years is a sufficient period of time to capture normal business cycles at an EUSGU. We do not believe that any information received during the public comment period for this final rule adequately supports a different conclusion. Thus, we have decided to retain the 2-in-5-years baseline period for EUSGUs. However, for consistency with the baseline period for other existing emissions units, we have specified that the 2-year period is a consecutive 24-month period.

2. Why Do the New Requirements Not Provide Discretion for the Reviewing Authority To Consider Another Time Period More Representative of Normal Operation for Non-EUSGUs?

Several commenters oppose our proposed elimination of the reviewing authority's discretion to allow a different representative period (outside of the 10-year period), because they argue certain sources (for example, emissions units placed in cold reserve due to reduced demand) require this flexibility. Some commenters say the discretion should be given to the reviewing authority, while other commenters wanted the discretion given directly to source owners and operators. Instead of the discretion to use an alternate period, one commenter prefers that all sources should be required to show that they have selected a representative period that precedes the most recent 2-year period.

We believe that use of a fixed 10-year look back period provides the desired clarity and certainty to the process of selecting an appropriate utilization/emissions level that is representative of a source's normal operation. A bounded 10-year look back provides certainty to the regulated community that may be undermined by an option to allow an unbounded alternative period as well.

3. Why Are We Placing Restrictions on the Use of a 10-Year Look Back for Setting the Baseline Actual Emissions?

Numerous commenters responded to our concern that many sources might lack accurate records for the full 10-year look back period, and to our request for comments on the need to condition the full use of the 10-year period upon the accuracy and completeness of available data, as well as the need to establish specific criteria for accuracy, completeness, and recordkeeping when using older data. A number of commenters generally support limiting full use of the 10-year look back period to situations in which adequate emissions and/or capacity utilization data are available. Some commenters also recommend that EPA issue minimum criteria to reduce the number of case-by-case determinations and help reviewing authorities avoid debates with sources on what constitutes sufficient data.

On the other hand, one commenter recommends that we not adopt a variable look back period based on the quality of the older data because it would "add considerable uncertainty and protracted debate to the process. . . ." If, however, we choose to limit the look back period based on the quality of older data, then this commenter and several others prefer provisions allowing for case-by-case decisions by State or local reviewing authorities over specific criteria established by EPA.

Today's amendments condition the full use of the new 10-year look back period on the accuracy and completeness of your records of emissions and capacity utilization, with respect to the 24-month period you select, for any emissions unit that undergoes a physical or operational change. *See,* for example, new § 52.21(b)(48)(*f*). As with all emissions calculations, accuracy and completeness are central elements for applicability determinations. In many cases, sources presently maintain accurate records on emissions and operations for only 3 to 5 years. Thus, we think it is appropriate to limit use of the full 10-year look back period when you do not have adequate data for the time period you wish to select. However, this limitation should be alleviated over time as sources begin to maintain records for longer periods to accommodate the 10-year look back opportunity.

We also agree that adequacy of any given data should be left to the case-by-case judgment of individual reviewing authorities. The type of data necessary to determine emissions will vary drastically from source category to source category and from process to process within a source category. At this time, we are not able to issue generic criteria that would apply to all types of industries.

We are further restricting your use of the 10-year look back for emissions units that are located in nonattainment areas and OTRs. In such cases, you are precluded from using any portion of the 10-year look back that precedes November 15, 1990—the date of the 1990 CAA Amendments—to establish baseline actual emissions for those units. This limit on the use of the 10-year look back is consistent the intent of the 1996 NPRM, which was originally proposed to apply to the use of the 10-year look back for any modification of an existing facility in a nonattainment

for the years 1982 to 1994 inclusive, based on the Office of Management and Budget's SIC codes for individual industries (OMB, 1987).

area or OTR. See 61 FR 38259 (July 23, 1996). However, because we are now beyond the point where the November 15, 1990 limit is relevant to modifications, we are only applying this limitation in the netting context with respect to emissions units changed within the contemporaneous period.

4. Why Were Changes Made to the Proposed Approach for Establishing Baseline Actual Emissions Using a 10-Year Look Back?

Commenters raise specific questions about how to use the 10-year look back to calculate an emissions unit's baseline actual emissions. Several commenters are concerned about how the utilization rate would be considered in the calculation. For example, some commenters support the proposal to allow sources to use their highest capacity achieved during any consecutive 12 months, because it provides improved flexibility in establishing a capacity level that is representative of normal operations. However, other commenters object to using the 12 months with the highest utilization. These commenters argue that the use of production rates can be unworkable because there is not always a clear relationship between production rate and emissions. In addition, reliable records may not be available to determine the highest production rates. As an alternative, commenters suggest using emissions from any 12-month period in the preceding 10 years, adjusted to reflect current rules, or allowing the source to use any 12-month period of its choice.

A related issue raised by commenters is whether to require any current Federal, State, or voluntary limit to be included in the establishment of the baseline actual emissions. Some commenters say these provisions would penalize sources that complied with other regulatory requirements or chose to implement pollution prevention programs. Commenters are particularly concerned that sources be given credit for voluntary reductions. However, other commenters support including all of these factors in the baseline to better represent actual emissions and avoid inconsistencies between emissions units that have permits and those that do not. Commenters also raise specific questions about how the calculation would include the effect of other emission limitations.

As described earlier, we have decided to require the use of a consecutive 24-month period within the 10-year look back instead of the proposed 12-month period to calculate the baseline actual emissions for any emissions unit that undergoes a physical or operational change, or is affected by such change. The longer 24-month period allows you to reference levels of utilization achieved in the past, but also eliminates the potential problem associated with short-term peaks that do not truly represent the unit's normal operation. In this respect, the use of a 24-month period is consistent with the pre-existing approach for calculating actual emissions.

With respect to commenters' concerns about being required to use the period of highest utilization, our reference in the proposal preamble to selecting the period of highest utilization was based on our general assumption that the period of maximum utilization also represents the period of highest pollution levels for the unit of concern. However, you are not required to select the period of highest utilization. The choice of which consecutive 24-month period within the 10-year window to use is up to you. The two restrictions on the selection of the appropriate consecutive 24-month period, as described earlier, are the availability of adequate and complete source records for the unit of concern and the limit on using dates earlier than November 15, 1990 for contemporaneous emissions changes in nonattainment areas and OTRs.

We agree with the concerns expressed by some commenters that the baseline actual emissions calculated from the consecutive 24-month period selected could yield a higher pollution level than a unit is currently allowed to emit. We do not believe that we should allow a source to take credit for baseline actual emissions that exceed the current, legally allowable emissions rate. Consequently, the new requirements require you to determine whether any legally enforceable limitations currently exist that would prevent the affected unit from emitting a pollutant at the levels calculated from the 24-month baseline period. The approach that we have adopted allows you to reference plant capacity that has actually been used, but not pollution levels that are not legally allowed at the time the modification is to occur. You will be required to make adjustments for voluntary reductions that you may have taken only to the extent that the reductions resulted from conditions that are legally enforceable limitations.

5. How Does the Change in the Baseline Period Affect Related Requirements Regarding Protection of Air Quality?

a. How Does the Extended Baseline Period Conform With the Special Modification Provisions Under Sections 182(c) and (e) of the Act?

Most commenters feel the proposed extension of the look back period fits within the design and intent of the special modification procedures set forth in sections 182(c) and (e) of the Act, applicable in serious, severe, and extreme ozone nonattainment areas. However, one commenter representing State and local air pollution control agencies considers the new requirements to be in significant conflict with the special modification procedures contained in those sections of the Act. The commenter indicates that this conflict could be resolved by deferring to relevant requirements for modifications in serious, severe, and extreme areas. The commenter adds that while NSR programs are tools to attain and maintain compliance with the NAAQS, they should not be available to undermine specific statutory and SIP requirements designed to resolve nonattainment problems.

We disagree with the commenter's concern that the use of a 10-year look back period to implement sections 182(c) and (e) of the Act for purposes of establishing a modified unit's baseline emissions will undermine any statutory or SIP requirements designed to address nonattainment problems. The two sections establish special procedures for determining whether a proposed modification of a major stationary source of ozone in a serious, severe, or extreme ozone nonattainment area will be subject to major NSR under part D of the Act. The Act is silent on the issue of how one is to determine whether a physical or operational change increases the amount of a pollutant for a changed emissions unit. We believe, therefore, that we have the authority to establish a regulatory procedure for making the required determinations concerning emissions increases resulting from physical or operational changes.

In light of the fact that the 10-year look back period may be used for emissions units (other than EUSGUs) that are involved in contemporaneous emissions changes (for netting purposes), it should be noted that the new requirements prohibit the use of the look back period earlier than November 15, 1990. Consequently, for emissions units whose contemporaneous emissions changes occurred before November 15, 2000, the consecutive 24-month period selected for calculating the baseline actual emissions relevant to the contemporaneous emissions change cannot include a date prior to November 15, 1990. It should be pointed out, however, that for modifications involving emissions of volatile organic compounds (VOC) in areas classified as ''extreme,'' the statutory language is clear that the increase in emissions resulting from the change is not required to be a significant increase, but rather that ''any increase'' that is projected using the new actual-to-projected-actual applicability test will trigger the applicable NSR requirements.

b. Will the Longer Look Back Period Related to the Baseline Actual Emissions Protect Short-term Increments and NAAQS?

Some commenters express concerns that the opportunity to take credit for older baseline actual emissions would result in adverse environmental consequences. One commenter specifically indicates that the proposed baseline actual emissions determination process, involving a 10-year look back, would allow significant increases in emissions to escape the ambient impact review requirements otherwise required by NSR.

Today's new rule modifies the way your NSR applicability determinations are made for changes made to existing emissions units. The new rule does not affect the way in which a source's ambient air quality impacts are evaluated. Compliance with the NAAQS is accomplished with air quality dispersion models using maximum allowable emission limitations (or federally enforceable permit limits) combined with operating factors, which consider either design capacity or actual operating factors averaged over the most recent 2 years of operation, from all modeled sources.[24] In addition, any increase in actual emissions, based on the existing definition of ''actual emissions,'' consumes PSD increment whether it occurs through normal source operation or as a result of a physical or operational change. As mentioned earlier, the existing definition of ''actual emissions'' continues to apply with regard to all NSR requirements other than the new source applicability tests. *See,* for example, new § 52.21(b)(21)(i). Thus, we do not believe there is a basis for concluding that the use of a longer look back period for determining a modified emissions unit's baseline actual emissions (for purposes of determining whether a physical or operational change will result in a significant emissions increase) will cause any adverse environmental impacts.

[24] Guidance for modeling NAAQS compliance under the PSD program is set forth in EPA's Guideline on Air Quality Models contained in appendix W of 40 CFR part 51. This guidance is incorporated by reference both in the Federal PSD regulations and in the minimum requirements for SIPs under the part 51 PSD regulations.

6. Why Was the Contemporaneous Period for Netting Not Also Changed to a 10-Year Look Back Period?

In the 1996 NPRM, we indicated that we were not proposing to extend the 5-year contemporaneous period along with the proposed 10-year look back period associated with the establishment of baseline actual emissions. *See* 61 FR 38259 (July 23, 1996). We did, however, solicit comments on the effect of the differing look back periods and any reasons why these periods should be the same. Commenters responded in a variety of ways to our request, with no clear consensus as to whether it would be appropriate to establish a uniform look back period. One commenter supports the 10-year contemporaneous period for reasons of consistency. Other commenters believe that it was reasonable to use two different time frames. Some commenters support retaining the 5-year contemporaneous period because changing it could have adverse effects on existing permit determinations. Several commenters support the selection of a different contemporaneous time frame than the existing 5-year period, but they differ in their recommendations for changing it. One suggests giving the source the option of choosing either a 10-year or 5-year contemporaneous period. Another commenter believes that a 1-year period would reduce confusion. Finally, another commenter proposes a 5-year contemporaneous period that would not mandate that 5 consecutive years be considered.

We do not believe that there is a compelling reason to change the existing 5-year contemporaneous period. The look back periods serve different purposes and need not be the same in order to effectively implement the NSR program objectives. States retain the flexibility in defining a different contemporaneous period under SIP-approved NSR programs, and may use that flexibility to adjust the contemporaneous period if they believe that a different period is more appropriate for their purposes under the new applicability requirements. *See,* for example, § 51.166(b)(3)(ii). Therefore, under today's new requirements, we have not changed the 5-year contemporaneous period under the Federal PSD program. It should be noted that for purposes of determining the baseline actual emissions of a contemporaneous change in emissions from an emissions unit that was an existing unit at the time of the contemporaneous change, the new requirements authorize a source to use the 10-year look back period.

7. Why Was the Demand Growth Exclusion Retained?

When we proposed to expand the scope of the WEPCO rulemaking to cover modifications at any existing emissions unit, we solicited comment on whether the demand growth exclusion (currently available only to EUSGUs) should also be available to all source categories. In 1998, we noted that there were problems that could arise with the demand growth exclusion. 63 FR 39860–39861 (July 24, 1998). Accordingly, we solicited comment on this new position.

Several regulatory agency and environmental commenters support the total elimination of the demand growth exclusion. These commenters maintain that a facility's post-change emissions increases due to demand growth could not be disassociated from those that resulted directly from the physical or operational change. These commenters believe the demand growth exclusion would be difficult to enforce. The demand growth exclusion would, they claim, also be burdensome because it would require projections, estimates, and post-modification evaluations of increased emissions to determine whether the increases were the result of increased demand.

On the other hand, numerous industry commenters oppose eliminating the demand growth provisions, stating that market factors do independently cause emissions increases absent physical and operational changes. These commenters maintain that when projected increased capacity utilization is in response to an independent factor, such as demand growth, the increased utilization cannot be said to result from the change and therefore may rightfully be excluded from the projection of the emissions unit's future-actual emissions. They further argue that such increases should not be included in post-change emissions even in the absence of a demand growth exclusion, as the increases would not be the result of the physical or operational changes that were made. Consequently, these commenters state that the proposed demand growth exclusion simply makes that principle explicit and eliminates confusion as to how emissions should be calculated. The same commenters who support retaining demand growth provisions for utilities also believe these provisions should be extended to non-utilities.

Under today's new requirements, you will be allowed to apply the causation provision as originally contained in the WEPCO amendments. Both the statute and implementing regulations indicate that there should be a causal link between the proposed change and any post-change increase in emissions, that is, ''* * * any physical change or change in the method of operation *that would result in* a significant net emissions increase * * *'' [emphasis added]. See, for example, existing § 52.21(b)(2)(i). Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as growth in market demand, you may subtract the emissions increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit. See for example, new § 52.21(b)(41)(ii)(*c*).

On the other hand, demand growth can only be excluded to the extent that the physical or operational change is not related to the emissions increase. Thus, even if the operation of an emissions unit to meet a particular level of demand could have been accomplished during the representative baseline period, but the increase is related to the changes made to the unit, then the emissions increases resulting from the increased operation must be attributed to the project, and cannot be subtracted from the projection of projected actual emissions.

8. Should Increases in Plant Utilization Be Reviewed as Potential Major Modifications?

Many commenters argue that emissions increases resulting from increased utilization should not be subjected to review as major modifications. They insist that EPA's policy and rules have always allowed increases in capacity utilization without triggering a modification, and not allowing utilization increases will limit new capacity to new emissions units instead of promoting increased efficiency at existing emissions units. One commenter argues that these sorts of changes do not require any sort of applicability determination and that Congress never anticipated that the NSR program would hamper a source's ability to increase utilization up to the original design capacity.

We believe that an increase in utilization should not trigger the major NSR requirements unless it is related to a physical or operational change. As explained earlier, the CAA only applies the major NSR requirements to emissions increases that are the result of a physical or operational change. Thus, we do not believe that the major NSR requirements should apply to a utilization increase unless the increase is related to the modification. Under today's final rules, you may exclude emissions related to an increase in utilization if you were able to accommodate the increase in utilization during the 24-month period you select to establish your baseline actual emissions and the increased utilization is not related to the change.

9. Why Must You Track Physical or Operational Changes That Increase a Unit's Design Capacity or Potential To Emit Post-Change Actual Emissions for a Longer Period of Time?

We raised this issue in the 1998 NOA. Several commenters support applying what we then termed the ''actual-to-enforceable-future-actual'' test to increases in design capacity or PTE because it would be inappropriate to automatically assume that such increases will affect normal operations, which would require the actual-to-potential test. They say that these types of modifications are common and do not generally increase emissions because they improve efficiency and add control devices.

One commenter explains that it is not uncommon for an emissions unit's capacity to be increased so as to speed up normal operations without increasing production, and that projected actual emissions could easily be calculated on the basis of past operating experience. On the other hand, another commenter indicates that it is very expensive to increase design capacity. Therefore, it can be assumed that a company would use the additional capacity as soon as it becomes available.

Several regulatory agency commenters support the use of the actual-to-potential test for modifications that increase design capacity or PTE. One of these commenters stated that such modifications would alter an emissions unit's normal operation and make previous actual emissions ''unreliable and irrelevant.''

We do not believe that every modification that includes added capacity or an increase in the PTE is intended for full use of that new capacity or PTE. Such actions could well be intended to enhance current operations without resulting in increased production or operation. Therefore, under today's new requirements, you are not required to count the emissions increase that would result from full use of new capacity or PTE if you conclude that: (1) Such capacity or PTE will not be fully utilized, and (2) the emissions increase resulting from that portion of the capacity that will be used will not result in a significant emissions increase from the modification or a significant net emissions increase at the source. The new requirements include a provision that requires you to monitor the emissions from the project for 10 years following the resumption of regular operation of the emissions units modified. The 10-year period reflects our determination that this time frame best captures the normal business cycle for industry in general. Thus, in situations where your proposed project will in fact add new capacity or PTE to an existing emissions unit, yet you determine that the objective of the physical or operational change is not to use the increased capacity, your calculation of representative projected actual emissions may reflect this. However, you must maintain adequate information for 10 years following the completion of the project to track the actual annual emissions from the units associated with the project. This represents a special condition that supersedes the normal 5-year period for the recordkeeping requirements being adopted today. During the 10-year period, you must report to your reviewing authority within 60 days after any year if the annual emissions, in tpy, from the project exceed the baseline actual emissions by a significant amount for the regulated NSR pollutant and if such emissions differ from the preconstruction projection.

10. Does the Actual-To-Projected-Actual Applicability Test Apply to Netting?

We did not specifically request comment on this issue in the 1996 proposal. Nonetheless, we received several comments that assert that use of different methods to compute an emissions increase and determine a net emissions increase would result in ''absurd results'' and require two separate accounting records. Other commenters oppose using the actual-to-future-actual test for netting. One commenter says that the sole purpose of the actual-to-future-actual test was to determine if an emissions increase will occur. One commenter says we should go further and revise the definition of ''contemporaneous'' to limit it to project activities (vs. plantwide) and reduce credits for shutdowns and curtailments.

As stated previously, we did not specifically request comment on this issue and we are not promulgating amendments to the netting regulations, on this point, at this time.

11. Should We Impose an Enforceable Projected Actual Emissions Level?

Some commenters on our 1996 proposal support the establishment of an enforceable limitation on the modified source's projected future emissions level. Other commenters support our specific proposal in the 1998 NOA to use the projected actual emissions as a temporary cap for the emissions units involved in the project, that is, an enforceable 10-year emissions level.

On the other hand, many other commenters oppose the concept, citing various reasons for their opposition. These included concerns that it would become a *de facto* baseline for any additional permitting and create additional enforcement liability, usurp State prerogatives, be inconsistent with the CAA, and require enforceable restrictions for too long. A few State and local air reviewing agencies indicate that they do not have the resources to adequately administer a program that would require permits to be issued for every physical or operational change at a major stationary source.

Today's new requirements follow the 1996 proposal. You will not be required to make the projected actual emissions projection through a permitting action. After considering the comments received, we are concerned that such a requirement may place an unmanageable resource burden on reviewing authorities. We also believe that it is not necessary to make your future projections enforceable in order to adequately enforce the major NSR requirements. The Act provides ample authority to enforce the major NSR requirements if your physical or operational change results in a significant net emissions increase at your major stationary source.

12. Why Are Modified Sources That Are Not Considered Major Modifications Not Required To Submit Annual Reports of Actual Emissions Under the New Requirements?

Several commenters support our proposal to require sources to track post-change emissions for a 5-year period so that there is a factual finding as to whether emissions from the modified units actually increased. These commenters believe that the requirement to track emissions is a needed safeguard and that it should not be too difficult to track various operating parameters. They add that non-utilities should be able to track emissions as well as utilities. Finally, commenters who oppose the proposed 10-year enforceable limit support retaining the 5-year tracking period in its place.

Many other commenters object to the burden that tracking would impose in the absence of any additional environmental benefit. Some commenters suggest ways to reduce the burden, such as not requiring sources to report emissions unless there is a problem or reducing the tracking period to 2 or 3 years. Another industry commenter suggests that we require an up-front notification to the reviewing authority whenever the actual-to-future-actual applicability test is used.

We agree with those commenters who recommend that you should be required to track emissions for a period of time following a modification. Thus, we have retained our proposed requirement to maintain annual emissions information for a period of 5 years following resumption of regular operations after the change. As discussed previously, we expanded this requirement to 10 years for changes that increase an emissions unit's capacity or its potential to emit a regulated NSR pollutant. However, although we proposed a requirement for annual emissions reporting, we have concluded that the combination of the recordkeeping requirements of this rule, along with a requirement to report to the reviewing authority any annual emissions that exceed your baseline actual emissions by a significant amount for the regulated NSR pollutant and differ from your preconstruction projection, is an equally effective way to ensure that a reviewing authority can receive the information necessary to enforce the major NSR requirements. Moreover, your reviewing authority has the authority to request emissions information from you at any time to determine the status of your post-change emissions.

In response to the concern that these requirements might impose unnecessary burdens, we have also included further limits. First, you are only required to keep records if you elect to use the actual-to-projected-actual applicability test to calculate your emissions increase from the project. Second, you are only required to keep the records if there is a reasonable possibility that your project might result in a significant emissions increase. Finally, you only need keep those records for projects that are not major modifications.

We also considered requiring you to submit an up-front notification to your reviewing authority, but concluded that this would result in an unnecessary paperwork burden. (EUSGUs, however, will be required to submit a copy of their projections to reviewing authorities before beginning actual construction.) We anticipate that a large majority of the projects that are not major modifications may nonetheless be required to undergo a permit action through States' minor NSR permit programs. In such cases, the minor NSR permitting procedures could provide an opportunity to ensure that your reviewing authority agrees with your emission projections. Requiring a separate notification would not provide the reviewing authority with any additional information in such circumstances. Accordingly, we believe today's requirements provide reviewing agencies with the ability to obtain all the information necessary to ensure compliance.

13. Why Are We Promulgating Different Reporting Requirements for Existing Emissions Units Than for EUSGUs?

Today we are finalizing slightly different requirements for EUSGUs than other industries. In 2000, boilers and turbines with greater than 25 MWe or 250 mmBTU/hr of generating capacity represented 76 percent of this nation's emissions of nitrogen oxides (NO_X) and 85 percent of this nation's emissions of SO_2 from stationary sources.[25]

In view of the disproportionate amount of emissions generated by EUSGUs compared to other industry sectors, we believe that it is appropriate for reviewing authorities to have information on construction and modification activities at EUSGUs readily available. Accordingly, we are requiring EUSGUs to provide a copy of their emissions projection to the reviewing authority before beginning actual construction of a project. We are also requiring them to report their post-change annual emissions for every year they are required to generate them. This approach also makes sense because it focuses the limited resources of both sources and agencies on the sources that matter most.

III. CMA Exhibit B

In addition to the proposed changes based on the 1992 WEPCO amendments (*see* section II of this preamble), the 1996 proposal package included alternative regulatory language that would enable you to determine whether

[25] Information supporting these values can be found in the docket for today's rulemaking.

your facility has undertaken a modification based on the facility's pre-change and post-change potential emissions instead of its actual emissions. This action was part of the settlement of a challenge to our 1980 NSR regulations by CMA and other industry petitioners. The exact language we proposed was set forth in Exhibit B to the Settlement Agreement, which is contained in the docket for this rulemaking.

Under this method, sources may calculate emissions increases and decreases based on the actual emissions method or the unit's pre-change and post-change potential emissions, measured in terms of hourly emissions (that is, pounds of pollutant per hour). Sources could use this potential-to-potential test for NSR applicability, as well as for calculating offsets, netting credits, and other ERCs.

We proposed to make several changes to the NSR regulations. First, we proposed to add the following exclusion to the definition of ''major modification'':

> A major modification shall be deemed not to occur if one of the following occurs: (a) there is no significant net increase in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour); or (b) there is no significant net increase in the source's actual emissions.

Second, we proposed to delete all references to ''actual emissions'' in the definition of ''net emissions increase'' and added language indicating that all references to ''increase in emissions'' and ''decreases in emissions'' in the definition of ''net emissions increases'' ''shall refer to changes in the source's PTE (as calculated in terms of pounds of pollutant emitted per hour) or in its actual emissions.'' Third, we proposed to modify the applicability baseline by eliminating the reference to the 2-year baseline period and to a method for determining actual emissions during the representative period. Finally, we proposed to provide express authorization for sources to use potential emissions in calculating offsets and in creating ERCs.

We also indicated in the preamble for the 1996 proposed rulemaking that if we promulgated the Exhibit B settlement as a final rule, the Exhibit B rules would need to be updated to reflect other rule changes since 1980, as well as relevant provisions of the 1990 Amendments.

Before proposing the Exhibit B language, we did a preliminary analysis of the impact on the NSR program of the Exhibit B changes. These changes would provide maximum flexibility to existing facilities with respect to determining if a significant net emissions increase would result from a physical or operational change. However, we also expressed concern about the environmental consequences associated with the Exhibit B provisions. For one, you could modernize your aging facilities (restoring lost efficiency and reliability while lowering operating costs) without undergoing preconstruction review, while increasing annual pollution levels as long as hourly potential emissions did not change. Also, Exhibit B would allow your facilities to generate netting credits and ERCs for offsets based on potential hourly emissions, even if never actually emitted. This could sanction greater actual emissions increases to the environment, often from older facilities, without any preconstruction review. In addition, actual emissions increases resulting from unreviewed projects could go largely undocumented until a PSD review is performed by a new or modified facility that ultimately must undergo review. By that time, however, a violation of an increment could have unknowingly occurred. We were also concerned that Exhibit B would ultimately stymie major new source growth by allowing unreviewed increases of emissions from modifications of existing sources to consume all available increment in PSD areas.

In our analysis supporting the 1996 proposal, we were unable to reach any conclusions as to the magnitude of any environmental impacts beyond noting that the effects would vary from State to State depending on how much cumulative difference exists between the unused potential emissions and actual emissions in a given inventory of sources and on the extent to which any unused potential emissions have been used in attainment demonstrations. However, our analysis did show that typical source operation frequently does result in actual emissions that are below allowable emission levels.

We received many comments in response to the 1996 proposal regarding CMA Exhibit B. Some commenters believe the potential-to-potential test appropriately focuses on the significant emissions changes that could produce an adverse environmental impact. Several other commenters believe that a potential-to-potential test would be environmentally detrimental. These commenters believe that CMA Exhibit B represents a substantial weakening of the PSD program with large increases in actual emissions, which in itself could lead to a significant deterioration of air quality. They also express concerns regarding the creation of paper credits and other impacts on the broader air quality planning process. One commenter states that the potential-to-potential test would conflict with SIPs that are based on actual emissions, threaten a State's efforts to make reasonable further progress (RFP) demonstrations, and interfere with emission credits relied on by SIPs. These commenters also cite the following concerns.

• The potential-to-potential test would allow sources to escape the major modification provisions and could virtually eliminate NSR in most modification cases.

• Once a facility has proceeded without NSR based on actual emissions, it would be difficult to take an enforcement action years later that would successfully require that facility to retrofit LAER and obtain offsets retrospectively.

We agree that a potential-to-potential test for major NSR applicability could lead to unreviewed increases in emissions that would be detrimental to air quality and could make it difficult to implement the statutory requirements for state-of-the-art controls.

After consideration, we believe some of the comments in support of Exhibit B have merit. As noted by commenters who supported the CMA Exhibit B proposal, a potential-to-potential test could simplify and improve the NSR process. According to commenters, the CMA Exhibit B approach would have the following benefits.

• Limit the scope of the program to encompass only those significant physical changes that Congress intended to cover

• Reduce unnecessary NSR costs and delays and improve compliance and enforcement

• Lower the cost of the NSR process by reducing the complexity of the NSR applicability determinations

• Facilitate applicability decisions at the plant level

The commenters also say that the CMA Exhibit B approach is more equitable than the existing actual-to-potential approach, which results in the capture of a source's unused capacity. These commenters prefer the potential-to-potential test because it would allow utilization increases. This provision is especially useful for sources in cyclical industries where using existing capacity is critical. Sources in sectors where utilization and demand are closely related would also benefit.

Our own concerns, coupled with the concerns expressed by some commenters, have caused us to reject the use of the Exhibit B regulatory changes for general purposes of determining whether a proposed physical or operational change would result in a major modification. For the reasons stated above, we do not believe that a potential-to-potential approach is acceptable for major NSR applicability as a general matter. However, we agree with the commenters in part—some of the benefits of a potential-to-potential approach are desirable. We believe that in more limited circumstances a ''potential-to-potential''-like approach would be acceptable. Therefore, we are promulgating two new applicability provisions that capture the benefits of a potential-to-potential approach but still have the necessary safeguards to ensure environmental protection—PALs, and the Clean Unit Test.

Today's rules provide for a PAL based on plantwide actual emissions. If you keep the emissions from your facility below a plantwide actual emissions cap, then you need not evaluate whether each change might be subject to the major NSR permitting when you make alterations to the facility or individual emissions units. The cumulative actual emissions become the *de facto* potential emissions for the plant, and you may emit up to the permitted level without going through major NSR, even if you are making changes to the facility. The PAL allows you to make changes quickly by allowing you to alter your facility without first going through major NSR review. It thus limits the number and complexity of NSR applicability determinations, and reduces unnecessary costs and delays. It also allows a plant manager to authorize changes, as long as the emissions remain under the permitted level, without first obtaining reviewing authority review. Furthermore, it provides an incentive to use state-of-the-art controls and install new, lower emitting equipment, which will allow sources to increase utilization. In return for the flexibility a PAL allows, you must monitor emissions from all of your emissions units under the PAL. Therefore, the PAL ensures good controls and protection of air quality. We believe there are other mechanisms for establishing PALs that would achieve beneficial results. For example, we believe PALs based on allowable emissions would produce flexibility and assure environmental protection, provided affected sources had adequate safeguards. Therefore, we intend in the near future to propose a rule that would adopt PALs based on allowable emissions.

Analogous to what the PAL does for facilities, the Clean Unit Test sets emission limitations or work practice requirements in conjunction with BACT, LAER, or Clean Unit determinations and identifies any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. The Clean Unit Test recognizes that if you go through major NSR review (including air quality review) and install BACT or LAER or comparable technology, then you may make any subsequent changes to the Clean Unit without triggering an additional major NSR review, as long as there is no need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT, LAER, or Clean Unit determination or to alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination. Therefore, for Clean Units, given that the permit is based on a determination that is protective of air quality, the new test would deem there is no emissions increase as a result of any physical change or change in the method of operation. With these provisions, sources will have improved certainty and flexibility, reduced burden, and opportunity for utilization increases without compromising air quality. Like the PAL, the Clean Unit includes necessary safeguards by requiring enforceable permit terms and conditions to ensure environmental protection.

IV. Plantwide Applicability Limitations

A. Introduction

Today we are adopting a final rule for a PAL option that is based on the baseline actual emissions[26] from major stationary sources. A PAL is an optional approach that will provide you, the owners or operators of major stationary sources, with the ability to manage facility-wide emissions without triggering major NSR. We believe the added flexibility of a PAL allows you to respond rapidly to market changes consistent with the goals of the NSR program.

The final rules we are adopting today also benefit the public and the environment. Reviewing authorities, usually States, can only establish a PAL by using a public process that affords citizens the opportunity to comment upon the proposed PAL. This process is designed to assure local communities that air emissions from your major stationary source will not exceed the facility-wide cap set forth in the permit unless you first meet the major NSR requirements. We believe that a PAL provides a more complete perspective to the public because in setting a PAL, your reviewing authority accounts for all current processes and all emissions units together and reflects the long-term maximum amount of emissions it would allow from your source. Moreover, to comply with a PAL you must meet monitoring requirements prescribed in the rules that ensure that both your reviewing authority and the public have sufficient information from which to determine plantwide compliance. Additionally, through the final PAL regulations, we are promoting voluntary improvements in pollution controls by creating an incentive for you to control existing and new emissions units to maintain a maximum amount of operational flexibility under the PAL. Most importantly, for pollutants subject to a PAL, we are prohibiting serial, small, unrelated emissions increases,[27] which otherwise can occur under our existing regulations.

If you choose to use it, we believe you will benefit from the PAL option because you will have increased operational flexibility and regulatory certainty, a simpler NSR applicability approach, and fewer administrative burdens. To comply with a PAL, you need to ensure that there are no emissions increases from your major stationary source, as measured against the PAL. For you to do that, there is no need for you to quantify

[26] In our 1996 proposal we used the term ''actual emissions,'' while today we are using the term ''baseline actual emissions.'' This change in terminology is consistent with the regulatory changes discussed in section II of today's preamble. Despite this change in terminology, there may be places in this section of the preamble where we still use the phrase ''actual emissions.'' In such cases we are either discussing PALs established under the old regulatory provisions, or summarizing and responding to comments received on the 1996 proposal.

[27] Under our current NSR program, you can make physical changes or changes in the method of operation without triggering major NSR applicability, provided the individual changes do not result in significant net emissions increases. We have interpreted this requirement to permit you to make unrelated changes that, standing alone, do not result in significant emissions increases and to allow such changes to occur without considering whether other contemporaneous emissions increases render the change significant. Over time you could undertake numerous unrelated projects without triggering major NSR, provided the individual projects did not increase emissions by a significant amount, thus allowing source-wide emissions to increase over time without requiring any emissions controls for these individual projects. For example, a large chemical plant that is located in an ozone attainment area adds a new product line in 2001 and properly avoids PSD (including the BACT requirement) by limiting the VOC emissions increase to 39 tpy. Later, in 2003 the plant adds a different product line and also properly avoids PSD by limiting VOC emissions from the new line to 39 tpy. For this example, two process lines at the same plant with total potential emissions (78 tpy) above the 40 tpy VOC significant level under PSD were properly permitted over a 3-year period without BACT applying to either new product line.

contemporaneous emissions increases and decreases for individual emissions units. Through the PAL we are allowing you to make timely changes to react to market demand and providing you additional certainty regarding the level of emissions at which your source will be required to undergo major NSR. The benefit to you is that you will not have to make numerous applicability decisions using different baselines. Also, in some situations where you would have been unable to ''net out'' a new project in the major NSR program, under a PAL you can begin construction on your new project without obtaining a major NSR permit, which can take from a few months up to 2 years. In addition, because you may make emissions reductions at emissions units under the PAL to create room for growth at other units, through the PAL we are providing a strong incentive for you to employ innovative control technologies and pollution prevention measures, to create voluntary emissions reductions to facilitate economic expansion.

B. Relevant Background

1. What Is a PAL and How Does a PAL Compare to Other Major NSR Requirements and Netting?

The concept of a PAL is simple. Under the Act, you are not subject to major NSR unless you make a ''modification,'' which by definition cannot occur without an emissions increase. CAA section 111(a)(4). A PAL is a source-wide cap on emissions and is one way of making sure that emissions increases from your major stationary source do not occur.

The existing regulations require ''major modifications'' to undergo NSR, and the existence of a ''significant net emissions increase'' at the facility is a necessary prerequisite to a ''major modification.'' *See,* for example, §§ 52.21(b)(2) & (3); *see also Chevron* v. *Natural Resources Defense Council,* 467 U.S. 837, 863–64 (1984). Under our current system, we determine whether a ''significant net emissions increase'' occurs at your major stationary source by focusing initially on the change to the emissions unit(s) and then broadening the analysis to include other changes within the source. In order to determine whether there is a ''significant net emissions increase'' under major NSR as revised today, you must establish a pre-change baseline for each change, project the actual level of emissions after the change, calculate the creditable emissions increases and decreases that have occurred that are contemporaneous with the change, and determine whether the change would result in a significant net emissions increase. We refer to this applicability process as ''netting'' under the major NSR regulations. Both you and reviewing authorities have maintained that the netting rules are unnecessarily complex and burdensome, and have urged us to craft rules that link NSR applicability to compliance with a predictable source-wide emissions cap. We are responding to that request with the PAL concept. A PAL is a voluntary,[28] source-specific, straightforward, flexible approach to account for changes, including alterations to existing emissions units and the addition of new emissions units, at your existing major stationary sources. Complying with the PAL ensures that there are no emissions increases that trigger major NSR. If your emissions of the PAL pollutant remain below the PAL, and you comply with all other PAL requirements, whatever changes occur at your plant will not be subject to major NSR for the PAL pollutant. Our July 23, 1996 proposal contains a thorough discussion of the proposed PAL concept and the background information used to develop the proposal.

2. Why Does EPA Believe That PALs Will Benefit the Environment?

Over the past several years, we have allowed use of major stationary source-wide emissions caps to demonstrate compliance with major NSR in a select number of pilot projects. We recently reviewed six of these innovative air permitting efforts and found substantial benefits associated with the implementation of permits containing emissions caps (among other types of permit terms offering greater flexibility than major NSR permitting programs).[29] Specifically, we reviewed on-site records to track utilization of these flexible permit provisions, to assess how well the permits are working and any emissions reductions achieved, and to determine if there were any economic benefits of the permits.

Overall, we found that significant environmental benefits occurred for each of the permits reviewed. In particular, the six flexible permits established emissions cap-based frameworks that encouraged emissions reductions and pollution prevention, even though such environmental improvements were not an explicit requirement of the permits. We found that in a cap-based program, sources strive to create enough headroom for future expansions by voluntarily controlling emissions. For instance, one company lowered its actual VOC emissions over threefold in becoming a synthetic minor source (that is, 190 tpy to 56 tpy). Other companies lowered their actual VOC emissions by as much as 3600 tpy by increasing capture, by using voluntary pollution prevention and other voluntary emissions control measures, and by reducing production rates.

Participants reported that having the ability to make rapid, iterative changes to optimize process performance in ways that minimize emissions, and that reduce the administrative ''friction'' (time delays and uncertainty) associated with making operational and equipment changes, encourages facilities to make changes that improve yields and reduce per-unit emissions. It is also critical for responding to product development needs and market demand, and for maintaining overall competitiveness.

Reviewing authorities consistently reported that the permits worked well and proved beneficial, and that there was a reduction in the number of case-by-case permitting actions they needed to undertake. Specifically, we found that flexible permit provisions (for example, emissions caps) are enforceable as a practical matter by using a mixture of mass balance-based equations, CEMS, and parameter monitoring. No emissions cap exceedances or violations of the monitoring provisions were experienced by any of the pilot sources. In addition, the monitoring and reporting approaches worked well and were generally of higher quality and of more extensive scope than those directly required by individual applicable requirements.

Based on the results of these pilot projects, we believe that PALs will over time tend to shift growth in emissions to cleaner units, because the growth will have to be accommodated under the PAL cap. Specifically, we expect that PALs will encourage you to undertake such projects as: replacing outdated, dirty emissions units with new, more efficient models; installing voluntary emissions controls; and researching and implementing improvements in process efficiency and use of pollution prevention technologies, so that you can maintain maximum operational flexibility. We also expect that you and the reviewing authority will need to devote substantially fewer resources to

[28] The term ''voluntary'' means that you have the option of entering into a PAL, rather than voluntary compliance with a PAL that is in place. Once you have a permit with PAL requirements, you must comply with the requirements.

[29] Results of our study are reported in ''Evaluation of the Implementation Experience with Innovative Air Permits.'' A complete copy of this report is located in the docket for today's rulemaking.

discussing and reviewing whether major NSR applies to individual changes. Thus, overall, we believe that PALs will prove to be as beneficial to the environment as they are to you and your reviewing authority.

3. What Did We Propose for PALs?

On July 23, 1996, we proposed to amend the NSR regulations to specifically authorize PALs and to clarify the methodology under which you can obtain a PAL. Under the proposal, your reviewing authority could have elected to include provisions in its SIP to allow you to apply for a permit that based your source's major NSR applicability on compliance with a pollutant-specific, source-wide emissions cap. We proposed that a facility's PAL would generally be based on source-wide ''actual emissions'' plus an operating margin of emissions less than a significant emissions increase. We also sought comment on the circumstances under which it would be appropriate to use something other than actual (for example, ''allowable'') emissions to set the PAL.

On July 24, 1998, we published a notice in the **Federal Register** seeking further comment on how the PAL regulations could be reconciled with several environmental and legal concerns. The notice discussed how the PAL alternative fits within the Act's requirements for determining if changes at existing sources are subject to major NSR. Today we are adopting final regulations that address the issues and comments raised in the 1998 notice and the 1996 proposal.

C. Final Regulations for Actuals PALs

Today's action establishes final regulatory provisions for actuals PALs. We are placing these requirements in the major NSR rules for nonattainment areas at § 51.165(f), and in the PSD regulations (applicable in attainment and unclassifiable areas) at §§ 51.166(w) and 52.21(aa).

The PAL option adopted today provides you with a voluntary alternative for determining NSR applicability. Actuals PALs are rolling 12-month emissions caps (that is, tpy limits) that include all conditions necessary to make the limitation enforceable as a practical matter. Through the regulations, we are allowing PALs on a pollutant-specific basis and are also allowing you to opt for actuals PALs for more than one pollutant at your existing major stationary sources. You must continue to apply the major NSR applicability provisions to air pollutants at your source for which you have no PAL.

This section sets forth the specific requirements for actuals PALs. The section addresses the following items: (1) The process used to establish a PAL and the public participation requirements; (2) how the PAL level is determined; (3) how long a PAL is effective and what happens when a PAL expires; (4) can a PAL be terminated before the end of its effective period; (5) how a PAL is renewed; (6) how a PAL can be increased during the effective period; (7) circumstances that would cause your PAL to be adjusted during the PAL effective period; (8) whether a PAL can eliminate enforceable emission limitations previously taken to avoid major NSR; (9) the compliance requirements and monitoring, recordkeeping, reporting, and testing (MRRT) requirements that the permit must contain for emissions units under your PAL; (10) the process for incorporating conditions of the PAL into your title V operating permit; and (11) an example of how an actuals PAL would work under the regulations finalized today.

1. What Are the Permit Application Requirements, What Is the Process Used To Establish a PAL, and What Are the Public Participation Requirements?

Under today's final rules, you must submit a complete application to your reviewing authority requesting a PAL. The application, at a minimum, must include a list of all emissions units, their size (major, significant, or small); the Federal and State applicable requirements, emission limitations and work practice requirements that each emissions unit is subject to; and the baseline actual emissions for the emissions units at the source (with supporting documentation). The calculation of baseline actual emissions must include fugitive emissions to the extent they are quantifiable. The reviewing authority must establish a PAL in a federally enforceable permit (for example, a ''minor'' NSR construction permit, a major NSR permit, or a SIP-approved operating permit program). To comply with our final regulations, the reviewing authority must provide an opportunity for public participation when issuing a PAL permit. This process must be consistent with the requirements at § 51.161 and include a minimum of a 30-day period for public notice and opportunity for public comment on the proposed permit. Where the PAL is established in a major NSR permit, major NSR public participation procedures apply. When establishing a PAL, you must comply with all applicable requirements of the reviewing authority's minor NSR program, including modeling to ensure the protection of the ambient air quality. Additionally, you must meet all applicable title V operating permit requirements. When adding new emissions units under a PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment. In contrast, when adding new emissions units that will require an increase in a PAL, you must comply with the reviewing authority's major NSR permit requirements for public notice, review, and comment.

2. How Is the Level of the PAL Determined?

We calculate the PAL level for a specific pollutant by summing the baseline actual emissions of the PAL pollutant for each emissions unit at your existing major stationary source, and then adding an amount equal to the applicable significant level for the PAL pollutant under § 52.21(b)(23) or under the CAA, whichever is lower.

You must first identify all your existing emissions units (greater than 2 years of operating history) and new emissions units (less than 2 years of operating history since construction). When establishing the actuals PAL level, you must calculate the baseline actual emissions from existing emissions units that existed during the 24-month period as described below. The baseline actual emissions will equal the average rate, in tpy, at which your emissions units emitted the PAL pollutant during a consecutive 24-month period, within the 10-year period immediately preceding the application for a PAL. Consistent with today's final rules, you will have broad discretion to select any consecutive 24-month period in the last 10 years to determine the baseline actual emissions. Only one consecutive 24-month period may be used to determine the baseline actual emissions for such existing emissions units. For any emissions unit (currently classified as existing or new) that is constructed after the 24-month period, emissions equal to its PTE must be added to the PAL level. Additionally, for any emissions unit that is permanently shut down or dismantled [30] since the 24-month

[30] The key determination to be made is whether an emissions unit is ''permanently shut down.'' This issue is discussed in the Administrator's response to a petition objecting to an operating permit for a facility in Monroe, Louisiana. See *Monroe Electric Generating Plant,* Petition No. 6–99–2 (Adm'r 1999). A copy of this decision is in the docket. In general, we explained in our ''reactivation policy'' that whether or not a

period, its emissions must be subtracted from the PAL level. Different rules apply for determining baseline actual emissions for EUSGUs. You should refer to the definition of baseline actual emissions to determine the specific method for calculating baseline actual emissions for your emissions units. Consistent with today's final rules for determining baseline actual emissions, your baseline actual emissions for an emissions unit cannot exceed the emission limitation allowed by your permit or newly applicable State or Federal rules (RACT, NSPS, etc.) in effect at the time the reviewing authority sets the PAL. This means that for the purpose of setting the PAL, your baseline actual emissions for an emissions unit will include an adjustment downward to reflect currently applicable requirements. Additionally, your reviewing authority shall specify a reduced PAL level(s) (in tpy) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. *See* section II of today's preamble for additional information on determining the baseline actual emissions for your emissions units.

3. How Long Can a PAL Be Effective and What Happens When a PAL Expires?

Through the final rules, we are requiring that the term of an actual PAL be 10 years. At least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL, you must submit a complete application either to request renewal or expiration of the PAL. If you meet this application deadline for a permit renewal, the existing PAL will continue as an enforceable requirement until the reviewing authority renews your PAL, even if the reviewing authority fails to issue a PAL renewal within the specified period of time.

As part of an application to request expiration of the PAL, you must submit a proposed approach for allocating the PAL among your existing emissions units. The reviewing authority will retain the ultimate discretion to decide whether and how the allowable emission limitations will be allocated, including whether to establish limits on individual emissions units or groups of emissions units. As under the PAL, your emissions units must comply with their allowable emission limitations on a 12-month rolling basis. However, the reviewing authority retains the discretion to accept monitoring systems other than CEMS, CPMS, PEMS, etc., from you to demonstrate compliance with these unit-specific limits.

Until the reviewing authority issues the revised permit with allowable emission limitations covering each of your emissions units, your source must comply with a source-wide multi-unit emissions cap equivalent to the PAL level. After a PAL expires, physical or operational changes will no longer be evaluated under the PAL applicability provisions.

Notwithstanding the expiration of the PAL, you must continue to comply with any State or Federal applicable requirements for a specific emissions unit. (BACT, RACT, NSPS, etc.) When the PAL expires, none of the limits established pursuant to §§ 51.166(r)(2), 51.165(a)(5)(ii), or 52.21(r)(4), which the PAL originally eliminated, would return under today's final rules.

4. Can a PAL Be Terminated Before the End of Its Effective Period?

Today's final rules do not contain specific provisions related to the issue of terminating a PAL. Decisions about whether a PAL can or should be terminated will be handled between you and your reviewing authority in accordance with the requirements of the applicable permitting program.

5. How Is a PAL Renewed?

As previously discussed, you must submit a complete application to renew a PAL at least 6 months prior to, but not earlier than 18 months from, the expiration date of your PAL. If you submit a complete application to renew the PAL by this deadline, the existing PAL will continue as an enforceable requirement until the reviewing authority issues the permit with the renewed PAL. As part of your renewal application, you must recalculate and propose your maximum PAL level, taking into account newly applicable requirements and the factors described below.

Your reviewing authority must review the complete application and issue a proposed permit for public comment consistent with the permitting procedures for issuing the initial PAL. As part of this public process, the reviewing authority must provide a written rationale for its proposed PAL level. If your source's PTE has declined below the PAL level, the reviewing authority must adjust the PAL downward so that it does not exceed your source's PTE.

In addition, the reviewing authority may renew the PAL at the same level without consideration of other factors, if the sum of the baseline actual emissions for all emissions units at your source (as calculated using the definition of ''baseline actual emissions'' at §§ 51.165(a)(1)(xii)(B), 51.166(b)(21), and 52.21(b)(21) as amended by today's final rules) plus an amount equal to the significant level is equal to or greater than 80 percent of the PAL level (unless greater than the current PTE of the major stationary source). However, if the baseline actual emissions plus an amount equal to the significant level is less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, cost effective emissions control alternatives, or other factors as specifically identified by the reviewing authority in its written rationale. For instance, a reviewing authority may determine that PAL levels are inconsistent with the levels necessary to achieve the NAAQS, or a State may determine that PAL levels need to be reduced to provide room for new economic growth in the area.

In some circumstances, such as in the example cited below, the reviewing authority may exercise its discretion in deciding that an adjustment is not warranted. We believe that such discretion is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic

shutdown should be treated as permanent depends on the intention of the owner or operator at the time of shutdown based on all facts and circumstances. Shutdowns of more than 2 years, or that have resulted in the removal of the source from the State's emissions inventory, are presumed to be permanent. In such cases it is up to the facility owner or operator to rebut the presumption.

adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits that operating under a PAL provides, and discourages you from undertaking voluntary reductions. If your source would ordinarily be subject to a downward adjustment, but you believe such an adjustment is not appropriate, you may propose another level. The reviewing authority may approve the level that you propose if it determines, in writing, that the level is reasonably representative of the source's baseline actual emissions. Similarly, the reviewing authority may determine that a lower level best represents the baseline actual emissions from the source.

Consistent with the effective period for the initial PAL, all renewed PALs will have a 10-year effective period.

6. How Can a PAL Be Increased During the Effective Period?

The reviewing authority may allow you to increase a PAL during the effective period if you are adding new emissions units or changing existing emissions units in a way that would cause you to exceed your PAL. However, today's rule only authorizes your reviewing authority to allow such an increase if you would not be able to maintain emissions below the PAL level even if you assumed application of BACT equivalent controls on all existing major and significant units (emissions units that have a PTE greater than a significant amount (as defined by § 52.21(b)(23) or the CAA, whichever is lower). Such units must be adjusted for current BACT levels of control unless they are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level. The PAL permit must require that the increased PAL level will be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

Your proposed new emissions unit(s) and your existing emissions units undergoing a change must go through major NSR permitting, regardless of the magnitude of the proposed emissions increase that would result (for example, no significant level applies). This is because the significant level for the pollutant is incorporated into the PAL. These emissions units must comply with any emissions requirements resulting from the major NSR process (for example, LAER), even though they have also become subject to the PAL program or remain subject to the PAL.

To request a PAL increase, you must submit a complete major NSR permit application. As part of this application, you must demonstrate that the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from your significant and major emissions units (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level), plus the sum of the allowable emissions of the new or modified existing emissions unit(s), exceeds the PAL.

After the reviewing authority has completed the major NSR process, and thereby determined the allowable emissions for the new or modified emissions unit(s), the reviewing authority will calculate the new PAL as the sum of the allowable emissions of the new or modified emissions unit(s), plus the sum of the baseline actual emissions of your small emissions units, plus the sum of the baseline actual emissions from significant and major emissions units adjusted for the appropriate BACT level of control as described above. Your reviewing authority must modify the PAL permit to reflect the increased PAL level pursuant to the public notice requirements of §§ 51.166(w)(5), 51.165(f)(5), or 52.21(aa)(5) of today's final rule.

7. Are There Any Circumstances That Would Cause Your PAL To Be Adjusted During the PAL Effective Period?

During the term of the PAL, at PAL renewal or at title V permit renewal, your reviewing authority may reopen your PAL permit and adjust the PAL level, either upward or downward, as needed by the reviewing authority. While certain activities require mandatory reopening, for others the reviewing authority may reopen at its discretion. The reviewing authority must reopen the permit for the following reasons: (1) To correct typographical/calculation errors made in setting the PAL or to reflect a more accurate determination of emissions used to establish the PAL; (2) to reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets; or (3) to revise a PAL to reflect an increase in the PAL.

The reviewing authority may reopen the permit to: (1) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date; (2) reduce the PAL consistent with any other requirement that is enforceable as a practical matter, and that the State may impose on the major stationary source under the SIP; or (3) reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an AQRV that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

While the final rule does not require your reviewing authority to immediately reopen the PAL permit to reflect newly applicable Federal or State regulatory requirements (for example, NSPS, RACT) that become effective during the PAL effective period, it does require the PAL to be adjusted at the time of your title V permit renewal or PAL permit renewal, whichever occurs first. Notwithstanding this requirement, today's final rule provides your reviewing authority discretion to reopen the PAL permit to reduce the PAL to reflect newly applicable Federal or State regulatory requirements before the time we otherwise require.

8. Can a PAL Eliminate Existing Emission Limitations?

An actuals PAL may eliminate enforceable permit limits you may have previously taken to avoid the applicability of major NSR to new or modified emissions units. Under the major NSR regulations at §§ 52.21(r)(4), 51.166(r)(2), and 51.165(a)(5)(ii), if you relax these limits, the units become subject to major NSR as if construction had not yet commenced on the source or modification. Should you request a PAL, today's revised regulations allow the PAL to eliminate annual emissions or operational limits that you previously took at your stationary source to avoid major NSR for the PAL pollutant. This means that you may relax or remove these limits without triggering major NSR when the PAL becomes effective. Before removing the limits, your reviewing authority should make sure that you are meeting all other regulatory requirements and that the removal of the limits does not adversely impact the NAAQS or PSD increments.

We are not taking a position on whether compliance with requirements contained in a PAL permit could serve to demonstrate compliance with certain pre-existing requirements on individual units. The reviewing authority may assess on a case-by-case basis whether any streamlining would be appropriate in the title V permit consistent with part 70 procedures and our existing policies and guidance on permit streamlining.

9. What MRRT (Collectively Referred to as ''Monitoring'') Requirements Must the Permit Contain for Emissions Units Under Your PAL?

Each permit must contain enforceable requirements that accurately determine plantwide emissions. A PAL monitoring system must be comprised of one or more of the four general approaches that meet the minimum requirements discussed below, and such monitoring systems must be approved by the reviewing authority. You may also employ an alternative approach if approved by the reviewing authority. Use of monitoring systems that do not meet the minimum requirements approved by the reviewing authority renders the PAL invalid. Any monitoring system authorized for use in the PAL permit must be based on sound science and must conform to generally acceptable scientific procedures for data quality and manipulation.

In return for the increased operational flexibility of a PAL, your permit must include sufficient data collection requirements to ensure compliance with the PAL at all times. In addition, the PAL permit must contain enforceable provisions that ensure that the monitoring data meet the minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

This section addresses a number of issues associated with the practical enforceability of PALs and describes concepts that you and reviewing authorities must follow when establishing your PAL. The issues addressed include the following.

- How do monitoring requirements for emissions units under a PAL differ from those for emissions units that are not under a PAL?
- What are the testing requirements for your emissions units under a PAL?
- What monitoring systems are appropriate to demonstrate compliance with your PAL?
- What information about your proposed data collection systems must be submitted to your reviewing authority for approval?
- What recordkeeping requirements must your permit contain to demonstrate compliance with your PAL?
- What reporting requirements for your PAL must your permit contain?

a. How Do Monitoring Requirements for Emissions Units Under a PAL Differ From Those for Emissions Units That Are Not Under a PAL?

Typically, when an emission limitation applies on a unit-by-unit basis, the monitoring must be sufficient to provide data that demonstrate that emissions do not exceed the applicable limit for a particular unit. Under this approach, if an emissions unit has to meet an NSPS VOC limit of 9 ppm, the monitoring need only demonstrate that VOC emissions are no higher than 9 ppm but not measure VOC emissions at any precise level below 9 ppm (for example, 7 ppm, 8 ppm).

In contrast, under a VOC emissions actual PAL, the VOC emissions from each emissions unit must be quantified (in tpy), generally each month as the sum of the previous 12 months of VOC emissions. Thus, it becomes necessary to require monitoring that quantifies the emissions from each emissions unit to ensure that the annual limit is enforceable as a practical matter. As a result, the monitoring requirements for emissions units under a PAL may be more stringent than for those emissions units not under a PAL. In many instances, your emissions units may have monitoring suitable for determining compliance with a unit-specific emission limitation on a periodic basis, in accordance with title V requirements, but that monitoring frequency of data collection may not be appropriate for ongoing emissions quantification for a 12-month rolling total. Thus, even if your emissions unit's monitoring meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), you must upgrade that monitoring if you request a PAL and the existing monitoring does not meet the minimum requirements of the PAL regulations.

All units operating under a PAL must have sufficient monitoring to accurately determine plantwide emissions for a 12-month rolling total. For example, a source owner or operator with five units must be able, at any time, to quantify the baseline actual emissions for the past 12 months for each of the five units. That source should, in advance, outline how it plans to monitor each of the units in order to quantify the emissions. If one of the five units cannot accommodate one of the monitoring options provided in the rule in order to quantify the emissions, then the source owner or operator would be incapable of demonstrating ongoing compliance with the source's PAL.

b. What Are the Testing Requirements for Your Emissions Units Under a PAL?

As part of your PAL application and as directed by your reviewing authority, you must use current emissions or other current direct measurement data to demonstrate that your monitoring systems accurately determine emissions from each unit subject to a PAL. You will need to collect such data from all units subject to the PAL, including those that are unregulated at the present time. If you do not have current emissions data, or if your emissions unit's operation and equipment have changed since collection of that data, you will need to obtain current, accurate data, typically by conducting performance tests or other direct measurements before submission of your complete permit application to obtain a PAL.

In addition, you will need to re-validate the data and any correlation to demonstrate that your monitoring systems continue to accurately determine emissions from each unit subject to a PAL. This re-validation must occur at least once every 5 years for the life of the PAL. Data must be re-validated through a performance evaluation test or other scientifically valid means that is approved by the reviewing authority.

You must conduct all testing in accordance with test methods appropriate to your emissions unit and applicable requirements. For example, among the test methods for measuring organic emissions are Methods 18, 25, 25A, and 25B, which can be found in 40 CFR part 60, appendix A. During testing, your emissions unit must operate within the range you wish to operate, so as to provide an accurate quantification of emissions across the entire range. This may require you to perform more than one performance test.

c. What Monitoring Systems Are Appropriate To Demonstrate Compliance With Your PAL?

The PAL monitoring system must be comprised of one or more of four general approaches: (1) Mass balance for processes, work practices, or emissions sources using coatings or solvents; (2) Continuous Emissions Monitoring System (CEMS); (3) Continuous Parameter Monitoring System (CPMS) or Predictive Emissions Monitoring System (PEMS) with Continuous Emissions Rate Monitoring System (CERMS) or automated data acquisition and handling system (ADHS), as needed; or (4) emission factors. Alternatively, another monitoring approach may be used if approved in advance by the reviewing authority. The monitoring approaches mentioned above must meet minimum requirements established by today's rule.

In the mass balance approach, you would consider all of the PAL pollutant contained in or created by any raw material or fuel used in or at your emissions unit to be emitted. Currently, we are limiting this approach to monitoring for processes, work practices, or emissions sources using coatings or solvents. In order to use the mass balance approach, you must validate the content of the PAL pollutant that is contained in or created by any raw material or fuel used on site. This validation may be accomplished by a regular testing program conducted by the vendor of the materials or by an independent laboratory. In addition, you are required to use the upper limit of any content range in the calculations, unless the reviewing authority determines that there is a site-specific data monitoring system in place at the unit or that there are data to support the use of another content within the range.

If your reviewing authority allows you to use a mass balance approach, then the PAL permit must require you to account for all material containing the PAL pollutant or use of all materials that could create PAL pollutant emissions (through chemical decomposition, by-product formation, etc.). For instance, if you are subject to a VOC PAL and your emissions units do not utilize add-on control devices, you may use a mass balance approach to determine compliance. For example, suppose over 1 month you were using 8 tons of solvent with 25 percent VOCs (as demonstrated using Method 311). You would be required to report and include 2 tons of VOC emissions (since $8 \times 0.25 = 2$) for that month to compare with the PAL, even though some of the VOCs may not ultimately be emitted. (For example, they could be retained in your emissions unit's product or in a process waste.)

A CEMS, coupled with a CERMS as well as an ADHS (collectively known as a CEMS), may be used to measure and verify the PAL pollutant concentration, volumetric gas flow (if applicable), and PAL pollutant mass emissions discharged to the atmosphere from each emissions unit emitting the PAL pollutant. If your source utilize a CEMS approach, you must ensure that the CEMS meets the applicable Performance Specifications in 40 CFR part 60, appendix B. The CEMS must be capable of data sampling at least once every 15 minutes. In addition, you must be able to convert the data obtained from the CEMS system to a mass emissions rate.

These types of monitoring systems are appropriate for emissions sources subject to respective SO_2, NO_X, carbon monoxide, particulate matter (PM), VOC, total reduced sulfur (TRS), or hydrogen sulfide (H_2S) regulations.

A CPMS or PEMS coupled with CERMS and ADHS (collectively known as parameter monitoring), may be used for emissions units as reviewed and approved by your reviewing authority.

To determine emissions, parameter monitoring relies on: (1) Use of physical principles; (2) parameters such as temperature, mass flow, or pressure differential; and (3) performance testing results. Users of parameter monitoring must show a correlation between predicted and actual emissions across the anticipated operating range of the unit.

An example is a source owner or operator who determines VOC emissions from an incinerator by multiplying the incinerator efficiency by the amount of VOC-containing material used. Three assumptions are built into the emissions algorithm: (1) The VOC content remains constant; (2) the control device reduction efficiency remains constant over the temperature range established during performance testing; and (3) the unit load remains constant. Checks on these assumptions are established by: ongoing monitoring requirements (for example, combustion chamber temperature and control device load); ongoing emissions testing requirements (for example, periodic re-evaluation of the correlation between combustion chamber temperature and control device efficiency); and ongoing testing of the VOC content of the material.

Another example of parameter monitoring is an organic emissions condenser. The parameter monitoring design in this case is based on the laws of physics and the physical properties of the material (for example, the lowest condensation temperature of the VOC constituent), the temperature of the condenser, and the maximum material feed rate.

Some parameter monitoring works by calculating emissions using data from monitored parameters and a neural network system to optimize performance of a unit. By measuring numerous parameters, the network can then automatically analyze current operations, as well as emissions, and make adjustments to optimize performance.

Establishing parameter monitoring is a resource-intensive effort, requiring extensive up-front testing, analysis, and development. Recently, we have developed draft performance specifications for evaluating appropriate, acceptable parameter monitoring accuracy, repeatability, and reproducibility (*e.g.*, Performance Specification 16). You and your reviewing authority should review these performance specifications in developing an interim protocol for using parameter monitoring to demonstrate continuous compliance with a PAL. Your approved protocol may require revision as we finalize performance specifications.

Today's rule requires you to re-validate your monitoring systems, including parameter re-certification emissions testing, at least once every 5 years during the PAL permit term. You may conduct such re-validation as part of any other testing required by other non-PAL program requirements, such as title V program requirements.

If a parameter monitoring approach is taken, the owner or operator must use current site-specific data to establish the emissions correlations between the monitored parameter and the PAL pollutant emissions across the entire range of the operation of the emissions unit. If the owner or operator cannot establish a correlation for the entire operation range, the reviewing authority shall, at the time of the permit issuance, establish a default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated during the operational times when an emissions correlation is not available.

Alternatively, the reviewing authority may decide that operation of the emissions unit during periods where there is no emissions correlation is a violation of the PAL. The PAL permit must include enforceable requirements if either of these alternatives to the required correlation for parameter monitoring are used.

Emission factors may be used for demonstrating compliance with PALs, so long as the factors are adjusted for the degree of uncertainty or limitations in the factors' development. In ascertaining whether an emission factor is appropriate, you and your reviewing authority should consider the contribution of emissions from the emissions unit in relation to the PAL, the size of the emissions unit, and the margin of compliance of the emissions unit. In addition, if the emission factor approach is taken, the emissions unit shall operate within the designated range of use for the emission factor.

The owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing using other monitoring approaches (if technically practicable) to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required. For example, should you demonstrate to your reviewing authority's satisfaction that the use of your emission factor would yield a result that is protective of the environment, then you may not need to conduct site-specific performance testing. An emissions unit is considered significant if the emissions unit has the potential to emit the PAL pollutant in amounts greater than those listed in § 51.165(a)(1)(x).

In the event you choose to use one or more emission factors for your significant or small emissions units, you bear the burden to prove to the reviewing authority that the emission factors are appropriate and adjusted for any uncertainty in the factors' development. By way of example, the sulfur dioxide emission factor for 2-stroke, lean-burn, natural gas fired reciprocating engines, $5.88 * 10^{-4}$ pounds of sulfur dioxide emitted per million British Thermal Unit (mmBTU) of natural gas combusted, as published in our *Compilation of Air Pollutant Emission Factors AP–42, Fifth Edition Volume 1: Stationary Point and Area Sources,* which is found on our Internet Web site at *http://www.epa.gov/ttn/chief/ap42/index.html,* represents an appropriate emission factor.

The reviewing authority may approve other types of monitoring systems that quantify emissions to demonstrate compliance with PALs. Other types of monitoring that may be approved include a Gas Chromatographic (GC) or a Fourier Transform Infrared Spectroscopy (FTIR) CEMS that relies on extractive techniques, coupled with a CERMS as well as an ADHS, to measure and verify the VOC concentration, volumetric gas flow (if applicable), and VOC mass emissions (in lb/hr) discharged from stacks (that is, non-fugitive emissions) to the atmosphere. For processes, work practices, or emissions sources subject to VOC or organic hazardous air pollutant (HAP) regulations, these types of monitoring systems may be used for each emissions unit emitting VOC.

d. *What information about your monitoring system must be submitted to your reviewing authority for approval?*

You need to propose a monitoring system as part of your PAL permit application submission to your reviewing authority. The monitoring system proposed must accurately determine plantwide emissions. In your permit application, you must describe how you will collect and transform data from each emissions unit subject to a PAL permit, so that the emissions from each unit can be quantified as a 12-month rolling total. In addition, you need to demonstrate how you can be assured the data are and remain accurate by describing how you will install, operate, certify, test, calibrate, and maintain the performance of your monitoring system(s) on each emissions unit that will be subject to the PAL.

You will also need to provide calculations for the maximum potential emissions without considering enforceable emission limitations or operational restrictions for each unit in order to determine emissions during periods when the monitoring system is not in operation or fails to provide data. In lieu of the permit requiring maximum potential emissions during periods when there is no monitoring data, you may propose another alternate monitoring approach as a backup. This backup monitoring, however, must still meet the minimum requirements for the monitoring approaches prescribed in the regulation.

Note that each monitoring system with applicable requirements contained in appendix B of 40 CFR part 60 must be installed, operated, and maintained according to the applicable Performance Specification of 40 CFR part 60, appendix B.

For purposes of determining emissions from an emissions unit, a unit is considered operational not only during periods of normal operation, but also during periods of startup, shutdown, maintenance, and malfunction'even if compliance with a non-PAL emission limitation is excused during these latter periods. Your reviewing authority may approve different monitoring for various operating conditions (for example, startup, shutdown, low load, or high load conditions as demonstrated through multiple performance tests) for each emissions unit. You must, however, use one of the accepted monitoring approaches, including alternative monitoring approved by the reviewing authority, for these periods or calculate the emissions during these periods by assuming the highest PTE without considering enforceable emission limitations or operational restrictions.

In addition, the rule permits the reviewing authority to use the reasonably estimated highest potential emissions for periods when your emissions unit operates outside its parameter range(s) established in the performance test, unless another method is specified in the permit, and include those emissions in the 12-month rolling total in order to demonstrate compliance with the PAL. Alternatively, the reviewing authority may decide that operation outside the range(s) established in the performance test is a violation of the PAL. The reviewing authority must decide how to handle emissions when the unit is operating outside the ranges established in the performance tests prior to the issuance of the PAL permit and must include appropriate enforceable conditions in the PAL permit.

For parameter monitoring to be approved by your reviewing authority, your proposed monitoring system must measure the operational parameter value(s) within the established site-specific range(s) of operating parameter values demonstrated in recent performance testing. The monitoring system must then record the associated PAL pollutant mass emissions rate for that period based on the correlations demonstrated with the current test data.

e. What Recordkeeping Requirements Must Your Permit Contain To Demonstrate Compliance With Your PAL?

Your permit must require you to maintain records of your monitoring and testing data that support any compliance certifications, reports, or other compliance demonstrations. This information should contain, but is not necessarily limited to, the following data.

- The date, place (specific location), and time that testing or measuring occurs
- The date(s) sample analysis or analyses occur
- The entity that performs the analysis or analyses
- The analytical techniques or methods used
- The results of the analyses
- Each emissions unit's operating conditions during the testing or monitoring
- A summary of total monthly emissions for each emissions unit at the major stationary source for each calendar month
- A copy of any report submitted to the reviewing authority
- A list of the allowable emissions and the date operation began for any new emissions units added to the major stationary source.

You must also record all periods of deviation, including the date and time that a deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction.

You must retain records of all required testing and monitoring data, as well as supporting information, for at least 5 years from the date of the monitoring sample, measurement, report, or application. Supporting information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all required reports. Instead of paper records, you may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review and does not conflict with other recordkeeping requirements.

You must also retain a copy of the following records for the duration of the PAL effective period plus 5 years: (1) A copy of the PAL permit application and any applications for revisions to the PAL; and (2) each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

f. *What reporting requirements for your PAL must your permit contain?*

You must provide semi-annual monitoring and prompt deviation reports. The terms and conditions of an approved PAL become title V applicable requirements that will be placed in your title V permit. Therefore, the reports required under title V may meet the requirements of the PAL rule, so long as the minimum reporting requirements listed in the regulations are met. You must submit a semi-annual emissions report to the reviewing authority within 30 days after the end of each reporting period. The reviewing authority will use this report to determine compliance with the conditions of the PAL, including the PAL level.

The compliance period for an actuals PAL emissions level is a consecutive 12-month period, rolled monthly. Block 12-month periods are not allowed (for example, Jan.-Dec. of each year). The emissions report must include the total baseline actual emissions of the PAL pollutant for the previous 12 months and compare the previous 12 months' total emissions with the PAL level to determine compliance. Additionally, the emissions report must identify: the site; the owner or operator; the applicable PAL; the monitored parameters, the method of calculation with appropriate formulas, any emission factors used, the capture and control efficiencies used and the calculated emissions; total monthly emissions (tons) and the equations used to compute this value for each of the 12 months before submission of the emissions report (or for all prior months if the PAL has not been effective for 1 year); total annual emissions (tpy); a PAL compliance statement; a list of any emissions units added or modified to the site; and information concerning shutdown of any monitoring system, including the method that was used to measure emissions during that period. Finally, in accordance with title V requirements, your permit will require all reports to be certified by your responsible official as true, accurate, and complete.

10. What is the process for incorporating conditions of the PAL into your title V operating permit?

As discussed previously, the reviewing authority establishes a PAL in a federally enforceable permit using its minor NSR construction permit process or the major NSR permit construction process and eventually rolling these requirements into its title V operating permit. The reviewing authorities' rules for establishing or renewing PALs must include a public participation process prior to permit approval of the PAL. The process must be consistent with the requirements at § 51.161 and include a minimum 30-day period for public notice and opportunity for public comment on the proposed permit. PALs established through the major NSR process are subject to major NSR public participation requirements. When adding a new emissions unit under an established PAL, you must comply with the reviewing authority's minor NSR permit requirements for public notice, review, and comment.

The process for incorporating the conditions of a PAL into the title V operating permit depends on whether the initial title V permit has already been issued for the source. If the initial title V permit has not been issued, a PAL created in a minor or major NSR permit would be incorporated during initial issuance of the title V permit. If the initial title V permit has already been issued, the PAL would be incorporated through the appropriate part 70 modification procedures. As discussed later in this preamble, we suggest that you request that your reviewing authority renew your title V permit concurrently with issuance of your PAL in order to align the two processes together and decrease the administrative burden on you and your reviewing authority.

Once a PAL is established, a change at a facility is exempt from major NSR and netting calculations, but could require a title V permit modification, as could any other change. Whether a title V permit modification would be required, and which permit modification process would be used, is governed by the current part 70 rule as implemented by the reviewing authority.

11. What is an example of an actuals PAL?

The following example is based upon a hypothetical source that wishes to obtain an actuals PAL under the final regulations adopted today.

A manufacturing plant (a major stationary source) located in a serious ozone nonattainment area seeks an actuals PAL for VOC in January 2002. The major source threshold for VOC in a serious ozone nonattainment area is 50 tpy and the significant level for VOC modifications is 25 tpy. The plant has 5 emissions units with a total PTE of 640 tpy of VOC. The PTE for VOC for each of the emissions units at the plant is as follows: (1) Unit A is 335 tpy; (2) unit B is 20 tpy; (3) Unit C is 125 tpy; (4) unit D is 60 tpy; and (5) unit E is 100 tpy. Units A, B, C, and D are existing emissions units with more than 2 years of operating history. Unit E has been in operation for only a year. Unit D was dismantled in year 2000 and is considered permanently shutdown.

For units A, B, C, and D, the source has selected July 1, 1996 to June 30, 1998 (a consecutive 24-month period) to determine baseline actual emissions. Unit A is subject to a RACT requirement that became effective in year 2000. The baseline actual emissions for each emissions unit during this period are as follows: unit A, 140 tpy (including RACT adjustment); unit B, 10 tpy; unit C, 90 tpy; and unit D, 20 tpy.

The actuals PAL level for VOC is = 260 + 100 ¥ 20 + 25 = 365 tpy

WHERE

- 260 tpy = the sum of the baseline actual emissions for emissions units A–D (with 2 or more years of operation)
- 100 tpy = the allowable emissions (PTE) of unit E, which was constructed after the 24-month period;
- 20 tpy = baseline actual emissions of unit D, which is permanently shut down since the 24-month period; and
- 25 tpy = significant level for VOC in a serious nonattainment area.

D. Rationale for Today's Final Action on Actuals PALs

We received voluminous comments and suggestions in response to the 1996 NSR proposal, the 1998 NOA, and numerous meetings with interested stakeholders. This section addresses the more significant comments we received. For a more detailed discussion of the comments received and our responses, please refer to the Technical Support Document included in the docket for this rulemaking. The comment areas addressed in this section include: (1) How do the PAL regulations meet the major NSR requirements of the Act? (2) Are PALs consistent with the concept of ''contemporaneity''? (3) Are PALs permissible in serious and severe nonattainment areas? (4) Is it appropriate for a PAL to be based on actual emissions? (5) How should actual emissions be determined in setting the PAL level? (6) Should emissions from shut down or dismantled units be excluded from a PAL? (7) Should a PAL include a margin for growth? (8) Should PALs be required to expire? (9) Should we require PALs to be adjusted at the time of PAL renewal? (10) Should certain new emissions units that are added under a PAL be required to meet some level of emissions control? (11) Under what circumstances should you be allowed to increase your PAL and how should we apply the major NSR requirements to that increase? (12) What monitoring requirements are necessary to ensure the enforceability of PALs as a practical matter? (13) Is EPA adopting an approach that allows area-wide PALs? and (14) When should modeling or other types of ambient impact assessments be required for changes occurring under a PAL?

1. How do the PAL regulations meet the major NSR requirements of the Act?

The PAL regulations adopted today meet the requirements of the CAA and are consistent with the Congressional purpose and intent underlying NSR. We believe the PAL regulations constitute a reasonable interpretation of the Act's definition of ''modification'' and are permissible under current law.

The definition of ''modification'' set forth in section 111(a)(4) of the Act is fundamental to determining major NSR applicability. Pursuant to the Act, the term modification means ''any physical change in or change in the method of operation of a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' The statute, however, does not prescribe the methodology for establishing a stationary source's emissions baseline from which emissions increases are measured. When a statute is silent or ambiguous with respect to specific issues, the relevant inquiry is whether the agency's interpretation of the statutory provisions is permissible. *Chevron U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 865 (1984).

Accordingly, EPA is exercising its discretion to develop reasonable alternatives to determine NSR applicability that are consistent with the statutory provisions and Congressional intent underlying the NSR requirements. We believe that the PAL regulations adopted today represent a permissible construction of the Act.

2. Are PALs consistent with the concept of ''contemporaneity''?

In the 1998 NOA, we solicited comment on whether and how a program that recognizes PALs as an alternate method for determining NSR applicability should address a particular legal concern: the need to have some ''contemporaneity'' between an emissions increase and any decrease relied upon to net the increase out of review. As we discussed in the 1998 notice, the current regulations specify that, to be creditable, emissions increases and decreases must have occurred within a ''contemporaneous'' period. Our current regulations governing SIP-approved programs do not specify a precise time frame. However, the Federal PSD rules generally only credit those emissions increases and decreases that occur within the 5 years preceding a given change. We established these regulatory requirements after the court's decision in *Alabama Power,* in which the court interpreted the Act as requiring plantwide bubbling in the PSD program, but stated that ''any offset changes claimed by industry must be substantially contemporaneous.'' 636 F.2d 402. In the 1998 notice, we sought comment on whether a PAL program that never required PALs to be periodically updated to reflect current emissions at the source would allow sources to make emissions reductions and hold them indefinitely, only to use them several decades later to offset new increases, and whether such a system would contravene the contemporaneity principle the court announced.

Many commenters, including several regulatory agencies, maintain that PALs are consistent with the NSR requirements under the Act. These commenters contend that the court gave EPA the discretion to define contemporaneity. See 636 F.2d 402 (''The Agency has discretion, within reason, to define which changes are substantially contemporaneous.''). Others contend that changes made under a PAL are not subject to the *Alabama Power* ''contemporaneity'' requirement because a change made under the PAL is either excluded from NSR or alternatively does not exceed the applicable NSR significance threshold. Therefore, they contend that netting is not implicated by such changes. On the other hand, a few commenters assert that PALs conflict with the purpose of the Act.

We believe that the concept of contemporaneity, as articulated in *Alabama Power* and as set forth in the regulations governing the major NSR program, does not apply to PALs. The PAL program differs in certain important respects from our current regulations and from the 1978 regulations at issue in *Alabama Power.* The *Alabama Power* court was not presented with the PAL approach for determining whether there was an increase in emissions and did not consider whether the principles it set forth in its opinion would apply to such an approach.

Under the 1978 PSD regulations (43 FR 26380), a source was subject to BACT review only if ''no net increase in emissions of an applicable pollutant would occur at the source, taking into account all emissions increases and decreases at the source which would accompany the modification.'' 43 FR 26385. The test for whether a ''major modification'' had occurred required the source to sum all accumulated increases in potential emissions that had occurred at the source since issuance of the regulations, or since issuance of the last construction permit, whichever was more recent. Reductions achieved elsewhere in the source could not be taken into account.

In *Alabama Power,* the D.C. Circuit held that EPA was correct in excluding from BACT review any changes that did not result in a net increase of a pollutant. 636 F.2d 401. It concluded, however, that EPA had incorrectly excluded contemporaneous decreases from the calculation of whether a ''major modification'' had occurred. *Id.* at 402–03.

The current regulations take contemporaneous decreases into account for all PSD review purposes. Under the current regulations, you look initially at the emissions unit undergoing the change and determine whether there will be a significant increase at that unit. If there is no significant increase at the unit, the inquiry ends there. While we continue to believe that this is a permissible approach, one drawback to this approach is that it allows a series of small, unrelated emissions increases to occur, which is discussed elsewhere in this preamble. If there will be a significant increase at the unit, then you expand the inquiry to other units at the source. You take into account contemporaneous increases and decreases at the source in determining whether there will be an increase for the source as a whole. Thus, you must calculate increases and decreases at individual units in order to arrive at a net figure for the entire source.

In contrast, under today's PAL regulations, the inquiry begins and ends with the source. Your PAL represents source-wide baseline actual emissions. As such, it is the reference point for calculating increases in baseline actual emissions. If your source's emissions will equal or exceed the PAL, then there will be an emissions increase at your source. There is no need to calculate increases and decreases at individual units.

Today's PAL regulations constitute a reasonable, though not the only, approach to determining whether there is an emissions increase at your source. While we believe that the principle of contemporaneity continues to be important for purposes of major NSR netting calculations, we do not believe that it is a necessary concept for purposes of PALs. This is because if your source has a PAL, you have accepted a different means of calculating an emissions increase for the PAL pollutant. The only relevant question is whether your source has reached or exceeded the PAL level.

Even though PALs are a new approach, they do not alter the fundamental question, which is whether there will be an increase in emissions from your source. For actuals PALs, we consider whether there will be an increase in baseline actual emissions. Because the PAL serves as the baseline for measuring an increase, we have taken steps to ensure that the PAL is reasonably representative of baseline actual emissions. In taking these steps, we have also ensured that actuals PALs as finalized today are consistent with the concept of contemporaneity, to the extent such a concept has any application in this context. One way of viewing a PAL is to focus on the increases and decreases at individual emissions units that, taken together, result in the net emissions from your source as a whole. As long as the decreases that have occurred during the term of the PAL are sufficient to offset any increase that occurs, total emissions for your source will remain below the PAL, and your source will not experience a ''significant net emissions increase.'' Viewed from this perspective, the term of the PAL constitutes the ''contemporaneous'' period. We believe that 10 years is a reasonable contemporaneous period for PALs for the following two reasons. First, we believe that a 10-year period is practical and reasonable both for you and for the reviewing authority. While a logical stopping point may seem to be 5 years in line with the title V permit period, setting a PAL can be a complex and time consuming process, so a 5-year period would be too short and hence not beneficial either to you or to the reviewing authority. Second, a study conducted by Eastern Research Group, Inc.[31] supported a 10-year look back to ensure that the normal business cycle would be captured generally for any industry.

In addition, we believe that the PAL renewal provisions ensure that each 10-year term represents a distinct ''contemporaneous'' period. The renewal process is designed to prevent decreases that occurred outside of the current 10-year PAL term from being used to offset increases during that term. At renewal, the reviewing authority must consider whether decreases have occurred at your source because of compliance with newly applicable requirements. Thus, for example, if the compliance date for a new RACT requirement occurred during the initial term of the PAL, and the reviewing authority has not already adjusted the PAL downward to account for that requirement, it must do so at renewal. More generally, the reviewing authority is required to evaluate baseline actual emissions and provide a written rationale for public comment if it determines that an adjustment to the PAL is warranted. As part of this process, the reviewing authority must adjust the PAL downward if your source's current PTE is below the PAL level. We believe that this adjustment is important for air quality planning purposes. Additionally, the reviewing authority may renew the PAL at the same level if your source's baseline actual emissions plus the significant level are equal to or greater than 80 percent of the PAL level without consideration of other factors. We believe that this level is reasonably representative of the source's baseline actual emissions. If your source's baseline actual emissions plus the significant level are less than 80 percent of the PAL level, the reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale. We recognize that fluctuations in baseline actual emissions will occur at most sources as part of the normal business cycle. We also recognize that requiring the reviewing authority to adjust the PAL downward if your source's baseline actual emissions do not equal 100 percent of the PAL level could create an incentive for you to maximize your baseline actual emissions. In addition, most sources do not emit at a level just below the maximum allowable level but rather build in a margin to prevent accidental exceedances. However, the PAL should be reasonably representative of baseline actual emissions so that it can continue to serve as the baseline for calculating an emissions increase. We have balanced these competing concerns in adopting a requirement, subject to the provisions noted below, to provide discretion to the reviewing authority to adjust the PAL level if baseline actual emissions plus the significant level do not equal at least 80 percent of the PAL level.

To maintain flexibility, today's actuals PAL regulations allow the reviewing authority to determine representativeness on a case-by-case basis. If you believe that the new PAL level that the reviewing authority proposes for your source is not representative of your source's baseline actual emissions, you may propose a different level. In addition, any person may propose a different level as being more representative of your source's baseline actual emissions. The reviewing authority may approve a higher or lower level if it determines that it is reasonably representative of your source's baseline actual emissions.

For example, assume that your source was designed to burn either fuel oil or natural gas, and that your source's permit allowed the use of either fuel. During the initial term of the PAL, you used only natural gas at the source and your source-wide emissions were consistently less than 80 percent of the PAL level. However, due to shifting market conditions, you expected to use fuel oil for a period beginning after PAL renewal. Under these circumstances, the reviewing authority could reasonably determine that a higher level would be more representative of your source's baseline actual emissions.

Similarly, your source might be designed to manufacture several different products, and your permit might allow you to switch from one product to another. During the initial term of the PAL, you might produce a

[31] Eastern Research Group Inc. report on ''Business Cycles in Major Emitting Source Industries'' dated September 25, 1997.

product associated with low emissions, resulting in source-wide emissions that were consistently less than 80 percent of the PAL level. However, you might be planning to produce a product that would cause the source to emit at a higher level following PAL renewal. This is another example of a circumstance in which the reviewing authority could reasonably determine that a higher level was more representative of your source's baseline actual emissions.

In addition, for SIP planning purposes, the reviewing authority may adjust the PAL level at its discretion based on air quality needs, advances in control technology, anticipated economic growth in the area, or other relevant factors.

Because of the safeguards described above, we believe that the actuals PAL program as finalized today ensures that the PAL will serve as an appropriate baseline for determining whether there is a significant net ''increase'' in overall emissions from the source, and thus whether the source is undergoing a ''modification.''

Moreover, we believe that a PAL approach satisfies Congressional intent to only apply the NSR permit process when industrial changes cause significant net emissions increases to an area and not when changes in plant operations result in no emissions increase from the major stationary source. *See Alabama Power,* 636 F.2d 401.

3. Are PALs Permissible in Serious, Severe, and Extreme Ozone Nonattainment Areas?

In our 1996 proposal, we requested comment on whether PALs could be implemented in serious and severe ozone nonattainment areas in a manner that was consistent with section 182(c)(6) of the Act. Section 182(c)(6) contains special provisions for major stationary sources that increase VOC emissions in serious or severe ozone nonattainment areas as a result of a physical change or a change in the method of operation. In some of these areas, the provisions also apply if you increase NO_X emissions. In general, these special provisions change the significant level for VOC emissions in serious and severe nonattainment areas from 40 tpy to greater than 25 tpy. They also specify that you must go through a major NSR permitting review if you have a net emissions increase in the aggregate of more than 25 tpy over a period of 5 years.

In addition, we requested comment on whether PALs could be implemented in extreme ozone nonattainment areas. Section 182(e)(2), which applies in such areas, provides that any physical change or change in the method of operation at the source that results in ''any increase'' from any discrete operation, unit, or other pollutant-emitting activity at the source, generally must be considered a modification subject to major NSR permit requirements, regardless of any decreases elsewhere at the source.

A few industry commenters believe that the ''accumulation'' provisions of CAA section 182(c)(6) should make no difference to the acceptability of a PAL in ''serious'' and ''severe'' ozone nonattainment areas. They contend that we have correctly concluded that CAA section 182(c)(6) only applies when net emissions at the source as a whole increase above the 25 ton level. Accordingly, any change that triggered CAA section 182(c)(6) would already have breached the PAL limits. On the other hand, an environmental commenter states that a PAL in a serious, severe, or extreme ozone nonattainment area could be problematic because it could allow for an increase at an emissions unit in situations where source-wide emissions would not exceed the PAL.

We agree with commenters who believe that the PAL approach does not conflict with the provisions of CAA section 182(c)(6). We do not interpret section 182(c)(6) to be a limitation on our ability to authorize PALs in serious and severe nonattainment areas. This section directs that when there is an increase meeting certain criteria, it may not be considered *de minimis*, but it does not specify the methodology by which an emissions increase must be calculated. Accordingly, we exercise our discretion in establishing the methodology, and we are doing so today by having the PAL serve as the actuals emissions baseline against which future emissions increases are measured. *Chevron U.S.A., Inc.* v. *NRDC, Inc.,* 467 U.S. 837, 865 (1984). If your source's emissions equal or exceed the PAL, it will trigger NSR, whereas maintaining plant emissions below the PAL ensures that there is no emissions increase. We believe that our interpretation reasonably implements the statutory purpose of the section, given that PAL sources agree to be subject to a plantwide cap that serves as the reference point for determining whether there has been an increase and given that the appropriateness of the PAL level is reviewed at 10-year intervals. Actuals PALs effectively prevent the uncontrolled, unrelated, small, serial emissions increases section 182(c)(6) is designed to address.

Because CAA section 182(e)(2) clearly requires consideration of increases at individual emissions units in extreme ozone nonattainment areas, PALs are not allowed in such areas, since any increase in emissions from any unit in those areas constitutes a modification.

4. Is It Appropriate for a PAL to Be Based on Actual Emissions?

In 1996, we proposed and sought comment on a broad range of alternative approaches for setting PAL emission limitations, including a PAL based on the following: (1) Actual emissions as defined under the current and then proposed regulations at § 51.166(b)(21)(ii); (2) actual emissions with the addition of an operating margin greater than the applicable significance rate; (3) for new stationary sources, limits established pursuant to a review of the entire facility under PSD; and (4) for nonattainment pollutants (in nonattainment areas), any emissions level completely offset and relied upon in an EPA-approved State attainment demonstration plan. 61 FR 38250, 38256 (July 23, 1996).

We received general support for the PAL concept and for the different approaches we proposed. Some comments express support for a PAL approach based on allowable emissions, and others indicate support for a PAL approach based on actual emissions. Some commenters generally believe that an allowables approach is necessary to ensure increased operating flexibility and capacity utilization. They also assert that an allowables approach would protect air quality management goals, because they claim that air quality planning historically has been based on permitted emissions levels. Other commenters believe that an actuals approach is preferable because it facilitates more accurate air quality planning and provides a more reliable basis for determining the availability of offsets.

We have concluded that a major stationary source's compliance with an actuals-based PAL system is a permissible means of assuring that a major stationary source does not have a significant emissions increase. We also conclude that this approach can be implemented in a manner that is consistent with the Act. Thus, in today's action, we are adopting regulations that authorize States to issue actuals PALs. We plan to address allowables PALs in an upcoming rulemaking.

5. How Should Actual Emissions Be Determined in Setting the PAL Level?

In the 1996 proposal, we requested comment on whether the definition of actual emissions for the purpose of determining the level of the PAL should be based on the definition of actual emissions in the current major NSR regulations, or whether it should be based on the proposed revisions to the actual emissions definition contained in that 1996 proposal. The fundamental difference between these two approaches is that the current NSR regulations would only allow you to look back 5 years to determine the actual emissions (the sum of actual emissions for all emissions units at your major stationary source). The 1996 proposed changes to this definition would allow you to look back 10 years to determine the actual emissions.

Several commenters prefer a 10-year baseline period for setting PALs based on actual emissions. A few commenters prefer a 5-year baseline period. One commenter advocates use of an actual emissions level that is initially based on the previous 2 years but that would decline over time.

In a separate section of today's final rules, we are finalizing changes to our definition of baseline actual emissions. Among other changes to the definition, you will be allowed to look back for a period of 10 years to establish the baseline actual emissions (except for EUSGUs). For program consistency and ease of implementation, we believe that the procedure for determining the baseline actual emissions for establishing your PAL should be the same as the baseline actual emissions that you will be required to use under the other major NSR program requirements. Accordingly, we are adopting an approach for establishing your actuals PAL that is consistent with how the baseline actual emissions are determined for an emissions unit under other requirements of the major NSR program.

We are, however, including a special allowance for emissions units that have operated for less than 2 years. Under such circumstances, the emissions unit has not operated long enough to establish a reliable baseline actual emissions calculation. Therefore, today's rule allows your reviewing authority to consider the allowable emissions of such emissions units when establishing or renewing the PAL. The baseline actual emissions of such emissions units would be adjusted to reflect a more representative level of baseline actual emissions at the time of the next PAL renewal.

6. Are Emissions From Shut Down or Dismantled Units Excluded From a PAL?

We proposed several options to adjust PAL levels to account for emissions units that are shut down or dismantled before setting a PAL. Several commenters support adjusting the PAL level for permanently shut down or dismantled units. A few commenters maintain that PAL adjustments are only appropriate for long-term shutdowns. Other commenters oppose allowing adjustments for shutdowns. They indicate that it would be difficult to implement and that it could penalize sources that were meeting environmental goals.

We agree with commenters that the baseline actual emissions used in establishing the PAL should exclude emissions from units that are permanently shut down or dismantled after the 24-month period selected for establishment of baseline emissions. We believe that excluding such emissions from your PAL level is appropriate for air quality planning purposes. Moreover, the environment has already seen the benefit of the reduced emissions. We also do not agree with those commenters who advocate adjusting the PAL only for long-term shutdowns, because it is too difficult to define and enforce ''long-term.''

As described in section IV.C.2 of this preamble, the PAL level includes baseline actual emissions from each existing emissions unit and new emissions unit at the source. For any emissions unit that has been permanently shut down since the 24-month period, its emissions should not be included in calculating the PAL level. Conversely, for an emissions unit that began construction after the 24-month period, the emissions (equal to the potential emissions of that emissions unit) must be included in setting the PAL level.

One shutdown option we considered, but did not adopt, is to exclude emissions from PALs only for units that did not operate at all during the 10-year life of the PAL. Under this option, the PAL would not be adjusted downward if you utilized those emissions from the shut down or dismantled units elsewhere at your source during the period since the shutdown (for example, by adding new emissions units or capacity, or by increasing capacity utilization at existing emissions units). As we indicated in our proposal, we believe it would be too difficult to determine whether you have actually relied on these emissions decreases in undertaking other activities at your source. We did not receive any comments suggesting ways to overcome this identified problem.

7. Does a PAL Include a Reasonable Operating Margin?

In the July 23, 1996 action, we proposed that a PAL for existing sources be based on source-wide actual emissions, including a reasonable operating margin less than the applicable significant emissions rate. We also requested comment on several other options for establishing a PAL. Several commenters support the option of basing the PAL on source-wide actual emissions plus a reasonable operating margin less than the applicable significance amount. Other commenters believe an operating margin tied to significant levels would be too restrictive.

Today we are finalizing an option that allows you to include, when setting the initial PAL, an amount that corresponds to the significant level for modifications of the PAL pollutant as specified in the major NSR rules [for example, in the PSD regulations at § 52.21(b)(23)(i)], or as specified in the CAA, whichever is lower. For example, for SO_2 PALs you may add to the PAL baseline level the 40 tpy significant level; for CO PALs you may add 100 tpy to the PAL baseline level. Also, for serious and severe ozone nonattainment areas the VOC significant level added to the PAL level is 25 tpy. For major sources of NO_X located in serious and severe ozone nonattainment areas, where NO_X is regulated as an ozone precursor, you may add to the NO_X PAL baseline the NO_X significant level of 25 tpy, and not the 40 tpy NO_X significant level specified under PSD. In extreme ozone nonattainment areas, PALs are not allowed since any increase in emissions in these areas constitutes a modification.

While other approaches to providing a reasonable operating margin may be consistent with the CAA, we believe that the approach we are adopting today comports most closely with existing regulatory provisions for major NSR applicability. That is, it assures that the environment sees no significant increases in emissions compared to the baseline actual emissions existing before the PAL is established.

In our 1998 NOA, we also requested comment on whether we should provide for an operating margin when renewing a PAL. We proposed four possible approaches for maintaining a reasonable operating margin, including an option that would include in the adjusted PAL level an operating cushion equal to 20 percent of the current PAL. In a separate section of the NOA, we also requested comment on how PALs should be adjusted for emissions units that have installed good emissions controls.

Many commenters indicate that we must provide for a reasonable operating margin. However, we generally received unfavorable comments on all the approaches we suggested. Several commenters believe that our suggested approaches do not provide an adequate operating margin. In responding to our request for comment on how to adjust PALs for emissions units that have installed good emissions controls, many commenters indicate that it would be inappropriate for EPA to ''confiscate'' such emissions reductions. Such an approach would encourage sources to pollute to maintain higher baseline emissions, and would penalize those sources who would voluntarily reduce emissions. At least one commenter maintains that both you and the environment should benefit from these reductions, and thus, you should be allowed to retain a portion of your voluntary emissions reductions.

We agree with some commenters that mandating an adjustment at renewal, based solely on current operations and emissions levels, would discourage the voluntary emissions reductions the PAL is specifically designed to encourage. We agree with commenters that both you and the environment should benefit from your commitment to comply with a PAL. Should you engage in voluntary emissions reductions, we believe you should be able to retain the accompanying flexibility that encouraged you to make these reductions. At the time of renewal, it may be very difficult for a reviewing authority to distinguish the reason for a decrease in your baseline actual emissions level. It could be because you have aggressively applied emissions controls, or because of a decrease in utilization, a loss of capacity, a desire to maintain a compliance margin, or any of a number of other reasons. Accordingly, we believe that it would be difficult to advise a reviewing authority to only retain a certain percentage of your emissions reductions that resulted from applying emissions controls. Therefore, for simplicity, and for what we believe to be a reasonable policy position to encourage you to voluntarily reduce emissions without a fear of a complete loss of operational flexibility, we are allowing your reviewing authority discretion to renew the PAL at an appropriate level. Hence, your reviewing authority may renew the PAL at the same level without consideration of other factors, if the baseline actual emissions plus the significant level is equal to or greater than 80 percent of the PAL level. If not, today's rules also allow your reviewing authority to renew the PAL at a different level if it determines that level is more representative of baseline actual emissions. See section II.D.9, ''Should we require PALs to be adjusted at the time of PAL renewal,'' for more information on our rationale for allowing this discretion.

8. Are PALs Required to Expire?

In our 1998 NOA, we announced that we were considering, and requested comment on, an approach that would require PALs to expire after 10 years unless you choose to renew the PAL. We proposed that the PAL term would be 10 years. Several commenters agree with our suggested time frame of 10 years for the term of a PAL. Others support a 5-year period, which would fit with the title V permit review period. Some commenters support a period longer than 10 years.

Today, we are finalizing rules that require a PAL to be effective for a period of 10 years. We believe that a fixed-term PAL provides you with an appropriate time of regulatory certainty and allows a sufficient period of time for planning long-term capital improvements.

We also agree with those commenters who think it is beneficial to align the PAL renewal process with the title V permitting process for your major stationary source. Similar to a PAL permit process, the title V permit process provides the public with a comprehensive review of your source. We believe that aligning the PAL permit with the title V process will allow you and your reviewing authority to consolidate the administrative process for the two permitting actions. It also provides the public with a better understanding of your emissions characteristics relative to the surrounding community. However, we do not believe that requiring PALS to be reviewed every 5 years, consistent with the title V renewal period, provides industry with a sufficient period of regulatory certainty. We also believe that while the overall administrative burden for you and the reviewing authority is reduced if you are complying with a PAL, the establishment of a PAL requires an initial commitment of substantial resources. Given this initial resource investment, we do not believe that a 5-year fixed term for a PAL provides you or your reviewing authority with an adequate incentive to participate in the PAL system. Thus, in an effort to balance the need for regulatory certainty, the administrative burden, and a desire to align the PAL renewal with the title V permit renewal, we believe a fixed term of 10 years, the equivalent of two title V effective periods (10 years), is most appropriate. You may elect to renew your PAL after 10 years, for a subsequent 10-year period, rather than allow the PAL to expire.

In order to align the PAL renewal process with the title V permitting process, we suggest that you request that the reviewing authorities renew title V permits concurrent with issuance of the initial PAL permit, regardless of how many years are actually left on your title V permit.

9. Are PALs Required To Be Adjusted at the Time of PAL Renewal?

In 1996, we requested comment on ''why, how, and when a PAL should be lowered or increased without being subject to major NSR.'' In 1998, we announced that we were considering an option that required PALs to be renewed to reflect new current baseline actual emissions. We were also considering requiring a PAL to be adjusted for unused capacity. Under this approach, we would adjust a PAL downward when an emissions unit operates below the capacity level that was used to establish the PAL. In our 1998 NOA, we expressed three reasons why it might be appropriate to require PALs to be periodically adjusted. First, we expressed concern that the allowable-to-allowable applicability system of the PAL would allow you to indefinitely retain the right to pollute at an historical level of actual emissions. Second, we were concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in the area. And third, we were concerned that a PAL may interfere with a State's ability to plan for attainment if your actual emissions to the atmosphere are lower during a SIP planning year than in a subsequent year.

Some commenters generally oppose any periodic reviewing or adjustment of a PAL. They believe that such an approach would limit operational flexibility, discourage efficiency improvements, and create disincentives for voluntary reductions. However, other commenters generally support an approach that would require a periodic adjustment to PALs.

We continue to have concerns with an approach that would allow a PAL to be renewed without any evaluation of the appropriateness of the current PAL level. We believe such an approach would be contrary to the Act, and contrary to the court's decision in *WEPCO* v. *Reilly,* 893 F.2d 901, 908 (7th Circ. 1990). In WEPCO, the court determined that one statutory purpose of the NSR requirements is ''to stimulate the advancement of pollution control technology,'' and that ''allowing increased production (and pollution) through the extensive replacement of deteriorated generating system'' without triggering NSR review would create ''vistas of indefinite immunity from the provisions of * * * PSD.''

We believe today's rules avoid this inappropriate outcome, by requiring the reviewing authority to evaluate your baseline actual emissions at the time of PAL permit renewal.

Although we believe that a periodic review of the level of the PAL may be necessary, and that this may result in an adjustment in your PAL to a level that is representative of your baseline actual emissions, we do not believe that we should mandate an adjustment to the PAL based on only one prescribed methodology. Such an approach could lead to inappropriate results, as discussed below. Instead, we believe that our concerns can be appropriately addressed by providing the States the authority to adjust the PAL based on what is representative of your baseline actual emissions.

We believe that some discretion in determining what is representative of actual emissions is appropriate, based in part on our experience with the pilot projects previously mentioned. In one instance, a participant voluntarily agreed to reduce its actual emissions by 54 percent in exchange for obtaining a source-wide emissions cap. After agreeing to this emissions reduction, the participant further reduced emissions by increasing capture efficiency and incorporating pollution prevention strategies into its operations. Unexpectedly, the participant also suffered an unusual economic downturn that caused a decrease in the rate of production and a corresponding decrease in actual emissions. At the time of renewal of the source-wide emissions cap, the participant's actual emissions were 10 percent of its actual emissions before committing to the emissions cap. The participant chose not to renew its emissions caps, because renewal required an automatic adjustment to its current actual emissions level. Clearly, such a result contravenes the mutual benefits operating under a PAL provides, and discourages you from undertaking voluntary reductions. Accordingly, although today's final rules require the reviewing authority to consider the need for adjusting the PAL when your current baseline actual emissions plus the significant level are less than 80 percent of your PAL level, it also provides the reviewing authority discretion to consider a variety of factors in determining whether the PAL should be adjusted.

We are also providing your reviewing authority discretion to take into account measures necessary to prevent a violation of a NAAQS or PSD increment, and to prevent an adverse impact on an AQRV in a Federal Class I area. For example, although we remain concerned that a PAL may allow you to retain unused emissions credits that would otherwise be available for economic growth in your area, we believe that managing an area's economic growth is the primary responsibility of the State. As such, the State, through your reviewing authority, should have discretion to manage the growth increment for your area. If your State wishes to encourage economic growth, then it may, at its discretion, reduce your PAL for that reason. Conversely, it may decide that encouraging economic growth is not a priority for the area and concurrently find no other concerns that warrant a downward adjustment in your PAL.

After further reflection, we also believe that it is inappropriate for us to mandate in all cases a prescribed methodology for adjusting PALs based on our concern that a PAL system may interfere with a State's ability to plan for attainment. We believe that the concern regarding planning for attainment is not unique to a PAL system. Most importantly, nothing in this rule reduces the State's discretion in developing plans to attain and maintain NAAQS. Under our major NSR applicability system, you could increase your emissions over your historical actual emissions by increasing utilization or hours of operation. If this occurs, there may be a discrepancy between the amount the State carries in the emissions inventory and the amount that you emit to the atmosphere. States should be cognizant of these issues and take appropriate measures in their SIP planning procedures to assure that emissions from any major stationary source, including a PAL participant, are properly characterized in the emissions inventory.

And finally, we agree with industry commenters that if we were to mandate an adjustment because your baseline actual emissions did not equal 100 percent of the PAL level, it would encourage you to increase production and emissions, and such an outcome would be counterproductive. We have accordingly provided your reviewing authority the ability to add a reasonable operating margin to your baseline actual emissions at the time of renewal. This operating margin was discussed previously in section II.D.7 above—''Should a PAL include a reasonable operating margin?''

10. Are Certain New Emissions Units That Are Added Under a PAL Required To Meet Some Level of Emissions Control?

We solicited comments on whether we should require you to control emissions from new emissions units that are added under an established PAL. Several commenters believe that BACT or LAER should not be required for these emissions units. A few commenters favor adding a requirement that BACT or LAER be required on new emissions units.

We believe that it is unnecessary to mandate a specific control level on new emissions units that you add under an established PAL. After reviewing the performance of a limited number of facilities that are participating in PAL pilot projects, we have concluded that these facilities' desire to maintain a large degree of operational flexibility under a PAL system has encouraged them to voluntarily install state-of-the-art controls on new emissions units. (See footnote 26 regarding our study, ''Evaluation of the Implementation Experience with Innovative Air Permits.'') We anticipate similar results as we extend the PAL program more broadly. Alternatively, we believe that you will add emissions controls to existing emissions units if this is a more cost effective approach to controlling your emissions. This is precisely the type of flexibility you should have for managing your total source-wide emissions under a PAL system. Furthermore, this cost effective approach was contemplated and supported by the statements of the court in *Alabama Power*. The court concluded that you should be allowed to add new emissions units if the new emissions from this unit could be ''set-off against decreases'' from other emissions units at the major stationary source. Accordingly, we do not believe that it is necessary to mandate the installation of emissions controls on new emissions units if you are able to continue to comply with your PAL even after installing the new emissions unit. If our projections on this matter prove to be incorrect in practice, we will consider revising our regulations in the future to require a specific control level on new and/or existing emissions units.

11. Under What Circumstances Are You Allowed To Increase Your PAL and How Are the Major NSR Requirements Applied To That Increase?

We proposed that whenever a PAL is increased due to the addition of a new unit, or due to a physical or operational change to an existing emissions unit, the units associated with the increase would be reviewed for current BACT or current LAER, air quality impacts modeling, and emissions offsets, if applicable. We noted that it may be difficult for a reviewing authority to determine which emissions units are associated with a physical change or change in method of operation when the emissions increase is the result of a source-wide production increase. We requested comment on five possible ways to apply the major NSR requirements when emissions increases are not directly associated with a particular change.

Commenters offered various suggestions for addressing emissions increases above the PAL. Several commenters believe that major NSR should only be applied to the emissions unit primarily responsible for the increase. Among the various commenters, there are a few supporters for each one of the options we proposed. In addition, one commenter suggests that we add *de minimis* increase levels; another suggests that we require offsets for each increase. Several industry commenters believe that we should not apply major NSR when an increase above the PAL is solely due to a production increase. One commenter believes all increases should be subject to BACT.

After considering the comments received, we agree with the commenters who believe that major NSR should only be applied to the emissions units (either new or modifications of existing units) primarily causing the increase. Accordingly, in the final regulations, we are confirming our proposed requirement that only those emissions units that are part of a PAL major modification would be subject to major NSR.

As discussed earlier, we believe that a PAL provides you with an incentive to control existing and new emissions units to maximize your operational flexibility under your PAL. We also recognize that there may be valid economic reasons for requesting an upward adjustment in a PAL. We are, however, concerned that if there were no restrictions on your ability to request a PAL increase, you would not have an incentive to control emissions. Therefore, under today's final rules, before the reviewing authority may approve a mid-term increase in your PAL, you must demonstrate that you are unable to maintain emissions below your current PAL even with a good faith effort to control emissions from existing emissions units. To make this demonstration, you must show that even if BACT equivalent control (adjusted for a current BACT level of control unless the emissions units are currently subject to a BACT or LAER requirement that has been determined within the preceding 10 years, in which case the assumed control level shall be equal to the emissions unit's existing BACT or LAER control level) were to be applied to all of your significant and major emissions units, the resulting emissions level will exceed your current PAL when combined with the emissions from both your small emissions units and your new emissions unit's allowable emissions.

12. What Compliance Monitoring, Reporting, Recordkeeping, and Testing (MRRT) Requirements Are Necessary to Ensure the Enforceability of PALs as a Practical Matter?

The MRRT requirements for PALs are addressed below. Numerous commenters, generally State agencies and environmental groups, state that adequate monitoring, reporting, and recordkeeping requirements would be necessary to ensure that the PAL limits were enforceable. Some commenters hold that the monitoring, recordkeeping, and reporting provisions would be too burdensome and restrictive. Some believe that PALs would not be viable because of these requirements.

Several commenters request that we clarify the monitoring that is necessary to show compliance with a PAL, especially in relation to the CAM and title V programs. Several commenters prefer that the monitoring requirements be flexible and simple. These commenters urge us not to use CAM, require CEMS, or establish stringent protocols. A few commenters prefer that we not define what would be enforceable as a practical matter for PAL limits. Others insisted that the PAL limits must be federally enforceable.

We believe that the PAL must assure that the source maintains emissions below the PAL level to assure that major NSR does not apply. Therefore, we agree with the commenters who stated that adequate data collection requirements through means such as monitoring, reporting, and recordkeeping requirements are necessary to ensure that the PAL limits are enforceable as a practical matter. In fact, we find that not only monitoring, recordkeeping, and reporting requirements, but also emissions testing requirements, for emissions units subject to a PAL differ from other MRRT in one important aspect: actual unit emissions must be measured to provide a 12-month rolling total, and compared against a limit. Currently, many emissions units are required only to have MRRT suitable for initial or spot checks on emissions concentrations, not emissions quantification. Even emissions units whose MRRT meets the title V requirements in §§ 70.6(a)(3)(i)(B) or 70.6(c)(1), including those imposed by part 64 (the CAM rule), may need to be upgraded when those units are proposed to become subject to a PAL, because the approved title V MRRT may not be able to count emissions against a cap. While we believe you can obtain data for emissions quantification best through the use of CEMS or PEMS, in today's final rule we are allowing you to propose other types of emissions monitoring quantification systems, depending upon such factors as the size category of the emissions unit and its margin of compliance.

13. Is EPA Adopting an Approach That Allows Area-Wide PALs?

In 1996, we proposed an option that would allow a State to adopt an area-wide PAL approach. Under such an approach, all major stationary sources within a given geographic area would have a PAL. Our 1996 proposal contained little detail on how this would be implemented.

While a few commenters support area-wide PALs, many more oppose them. State agency commenters generally believe they would need time to develop PALs consistent with the approaches provided in the final NSR rule, as well as to develop data management and compliance assurance approaches that would accommodate the PAL approach. Thus, adding the area-wide PAL at the same time as the source-specific PAL may create several administrative headaches. Industry commenters maintain that area-wide PALs would ratchet down emissions and reduce flexibility.

We agree with the many commenters who opposed an area-wide PAL system, believing that the approach would be complex and resource and time intensive. We also perceived little interest in such an approach from the various stakeholders with whom we have met. Accordingly, we are not including any provisions in our final rules to implement an area-wide PAL system. However, we are not precluding such a program either. If a State currently has or wants to pursue an area-wide PAL program, then it must demonstrate that its program is equivalent to or more stringent than our final rules.

14. When Should Modeling or Other Types of Ambient Impact Assessments Be Required for Changes Occurring Under a PAL?

In our 1996 proposal, we requested comment on when modeling or other air quality impacts analysis is needed for changes occurring under a PAL to demonstrate protection of NAAQS, increments, and AQRVs.

One environmental commenter recommends modeling or other types of ambient impacts assessment whenever a change in emissions occurred under the PAL. One commenter recommends that FLMs be consulted whenever changes under the PAL are proposed, to determine whether an impact analysis for adverse impact on AQRVs would be necessary. Several commenters recommend modeling whenever a significant change occurred, but also recommend that EPA define significant change and how the modeling would be conducted. A facility could report the modeled effects of a minor change after the change is made (in a quarterly, semi-annual, or perhaps annual modeling summary), while more significant changes should be modeled prior to construction. The facility could be given a lot of responsibility in these cases and then held accountable (that is, required to mitigate) should an air quality increment or NAAQS be exceeded. These commenters also recommend that the impacts evaluation should be conducted at the time the PAL is established and that the PAL should clearly define what flexibility the source is allowed without further review and the types of changes for which additional review will be required. Some commenters generally believe that the proposed regulatory language concerning changes to PALs for air quality reasons was too vague and broad, but only a few of these commenters directly oppose modeling for changes under the PAL. One commenter states that if many changes were to require ambient air quality analysis, the PAL approach would have little if any benefit. The commenter believes that sources ought to discuss up front with permit authorities which emissions shifts might have consequences that would later require additional modeling/monitoring. If questions existed about certain emissions sources under a PAL, PALs could be approved with conditions assuring that certain post-approval modeling analysis be submitted.

In today's final rules, we believe we can rely on the reviewing authority's existing programs for addressing air quality issues. Certain changes in effective stack parameters under the PAL would generally be covered by the reviewing authority's minor NSR construction permit program. The reviewing authority would ordinarily request air quality modeling for any changes if it believes that the changes under the PAL may affect the NAAQS and PSD increments.

V. Clean Units

A. Introduction

In today's final rulemaking, we are promulgating a new type of applicability test for emissions units that are designated as Clean Units. This new applicability test will measure whether an emissions increase occurs, based on whether the physical change or change in the method of operation affects the Clean Unit status of the unit. This new applicability test provides that when you meet emission limitations based on installing state-of-the-art emissions control technologies (add-on control technology, pollution prevention techniques, or work practices) that are determined to be BACT or LAER, you may make any physical or operational changes to the Clean Unit without triggering major NSR, unless the change causes the need for a revision in the emission limitations or work practice requirements in the permit for the unit adopted in conjunction with BACT, LAER, or Clean Unit determinations, or would alter any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. Emissions units that have not been through major NSR may also qualify for the Clean Unit applicability test if you demonstrate that their emission limitations based on their emissions control technology (that is, add-on control technology, pollution prevention technique, or work practice) is comparable to BACT or LAER and you demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. To be comparable to BACT/LAER, the controls must meet the specific comparability test that we describe in section V.C.3 of this preamble. That is, you must show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RACT/BACT/LAER Clearinghouse (RBLC); or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

The Clean Unit applicability test benefits the public and the environment by providing you with an incentive to install state-of-the-art emissions controls, even if you would not otherwise be required to control emissions to this level. You will benefit from these final rules because they provide you with increased operational flexibility. Once you have installed state-of-the-art emissions controls on an emissions unit and it is considered a Clean Unit, you may make changes to respond rapidly to market demands without having to obtain a preconstruction major NSR permit. Moreover, you and your reviewing authority will benefit from increased administrative efficiency. We believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. In such cases, the major NSR permitting requirements impose a paperwork burden with little to no additional environmental benefit. The Clean Unit applicability test eliminates this unnecessary administrative action.

B. Summary of 1996 Clean Unit Proposal

In the 1996 NSR Reform package, we proposed an innovative approach to NSR applicability called the Clean Unit Exclusion. The proposed Clean Unit Exclusion would allow you to modify qualifying emissions units without being subject to the NSR permitting process for a period of 10 years, as long as your maximum hourly emissions rates would not increase. We proposed that your pre-change hourly potential emissions rate must be established at any time up to 6 months prior to the proposed activity or project.

We proposed three methods by which an emissions unit could qualify for the Clean Unit Exclusion. One was that the emissions unit went through a major NSR action within the last 10 years and had an enforceable limit based on BACT or LAER. The second was if the emissions unit was permitted under a State or local agency minor NSR program within the last 10 years and the minor NSR control technology requirements were comparable to BACT or LAER. As part of this second method, we proposed that State and local agencies would submit their minor NSR programs for certification so that case-by-case determinations for emissions units permitted under a minor NSR program would not be necessary. The third method was a case-by-case determination that an emission limitation was comparable to BACT or LAER for that emissions unit. For these units, we proposed that the Clean Unit Exclusion would last for 5 years. We proposed that a determination that a limit was comparable to BACT or LAER could be based on one of two methods: (1) the average of the BACT or LAER for equivalent sources over a recent period of time (such as 3 years); or (2) the unit's control level is within some percentage (such as 5 or 10) of the most recent, or average of the most recent, BACT or LAER levels for equivalent or similar sources.

In addition, we asked for public comment on whether Clean Unit status should apply to emissions units with limits based on MACT or RACT. Although we did not propose accompanying regulatory language, we suggested that reviewing authorities use the title V permitting process to designate Clean Units.

C. Final Regulations for Clean Units

1. Summary of Final Action

Today's rule provides that your emissions unit qualifies as a Clean Unit, and qualifies to use the Clean Unit applicability test, if it has gone through a major NSR permitting review and is complying with BACT or LAER. Conversely, if your emissions unit has not gone through a major NSR permitting review, you do not automatically qualify for Clean Unit status. These emissions units must first go through a SIP-approved permitting process that includes a process for determining whether the emissions unit meets the criteria to be designated as a Clean Unit. This process must include public notice and opportunity for public comment.

To obtain Clean Unit status and qualify for the Clean Unit applicability test using a SIP-approved permitting process, you must pass a two-part test: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. You may make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

If your emissions unit automatically qualifies as a Clean Unit because it has been through major NSR permitting, you may use the Clean Unit applicability test for up to 10 years. Today's rules allow you to apply for Clean Unit status for control technologies you have installed in the past if you go through a SIP-approved permitting program that authorizes Clean Units and you qualify as a Clean Unit. The Clean Unit effective period for emissions units that must go through a SIP-approved permitting process to obtain Clean Unit status is consistent with the time frame for emissions units that automatically qualify as Clean Units. That is, you may only use the Clean Unit applicability test for a period of 10 years. If you meet the requirements that we describe in section V.C.9 of this preamble, you may re-qualify for Clean Unit status. Upon expiration of Clean Unit status, the Clean Unit applicability test no longer applies to changes at the emissions unit.

It is worth noting that in 1996, we proposed the provisions for Clean Units as a ''Clean Unit Exclusion,'' although we discussed the provisions as a new applicability test. We received criticism from at least one commenter that our characterization of the test as an exclusion was inappropriate. We agree with this commenter, and have thus renamed the test as the Clean Unit applicability test. We believe that this title more appropriately reflects that the test is not whether you are excluded from review under major NSR, but whether using a more appropriate emissions test you trigger major NSR review.

2. Is Clean Unit Status Available in Both Attainment and Nonattainment Areas?

You may obtain Clean Unit status regardless of whether you are located in an attainment area or in a nonattainment area. Our proposed Clean Unit provisions were unclear on how emissions offsets and other nonattainment area requirements are affected by Clean Unit status. We want to clarify this issue. For sources in nonattainment areas which went through major NSR permitting while the area was nonattainment or which have qualified for Clean Unit status showing they are comparable to LAER, the permitted emissions level for the Clean Unit must have been offset. The emissions reductions resulting from installation of the control technology that is the basis of an emissions unit's status as a Clean Unit may not be used as offsets; however, emissions reductions below the level that qualified the unit as a Clean Unit may be used as offsets if they are surplus, quantifiable, permanent, and federally enforceable. Furthermore, for emissions units that are designated as Clean Units and that are located in nonattainment areas, RACT and any other requirements for nonattainment area sources under the SIP will still apply. The only exception to this is that the specific major NSR requirements related to calculating emissions increases from a physical change or change in the method of operation for all other existing sources that we describe in this preamble and codify in today's rules are not applicable to Clean Units, because the Clean Units are subject to an alternative major NSR applicability requirement for calculating emissions increases when changes are made.

As we discuss in detail in section V.C.3 of this preamble, the ''substantially as effective'' test for sources in nonattainment areas must consider only LAER determinations, except that emissions units in nonattainment areas that went through major NSR permitting while the area was designated an attainment area for that regulated NSR pollutant, and that received a permit based on a qualifying air pollution control technology, automatically qualify as Clean Units.

If your emissions unit received Clean Unit status while the unit was located in an attainment area and the area's attainment status subsequently changes to nonattainment, your emissions unit retains Clean Unit status until expiration. However, to re-qualify as a Clean Unit (see section V.C.9), the unit will have to meet the requirements that apply in nonattainment areas.

3. How Do You Qualify As A Clean Unit?

Any emissions unit permitted through major NSR automatically qualifies as a Clean Unit, provided the BACT/LAER determination results in some degree of emissions control. (We discuss the specific requirements for qualifying controls in section V.C.4 of this preamble.) These units already meet both the control technology and air quality criteria of the CAA and the NSR regulations. We believe that the emission limitations (based on the BACT/LAER determination) and other permit terms and conditions (such as any limits on hours of operation, raw materials, etc., that were used to determine BACT/LAER) are protective of air quality. Although emissions units that have been through major NSR automatically qualify for Clean Unit status, there are specific procedures for establishing and maintaining Clean Unit status. We discuss these procedures in detail in sections V.C.6 through 9 of this preamble.

Your emissions units that have not gone through a major NSR permitting action that resulted in a requirement to comply with BACT or LAER may qualify for Clean Unit status if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment. You must pass a two-part test to obtain Clean Unit status: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

You may show that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) By comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

To make a demonstration using the first methodology in a nonattainment area, you must compare your control technology to the best-performing 5 similar sources in the RBLC for which LAER has been determined within the past 5 years. If the emission limitation that is achieved by your control technology is at least as stringent as any one of the 5 best-performing units, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that it qualifies as a Clean Unit. In attainment areas, you must compare your control technology to all BACT and LAER decisions that have been entered into the RBLC in the past 5 years, and for which it is technically feasible to apply the BACT or LAER control to your emissions unit type. If your control technology achieves a level of control that is equal to or better than the average of these determinations, and the emissions unit also passes the air quality test, then the reviewing authority shall presume that your emissions unit qualifies as a Clean Unit.

After you have submitted your demonstration, the reviewing authority will also consider other BACT/LAER determinations that are not included in the RBLC to determine whether the proposed emissions rate is comparable to BACT/LAER, and incorporate this information into its determination as appropriate. In addition, the public will have an opportunity to review and comment on the reviewing authority's decision to designate an emissions unit as a Clean Unit. This approach ensures that you are meeting an emissions level comparable to that of BACT or LAER, while providing you flexibility to use the controls that are best suited to your processes.

We are providing this first methodology as a streamlined methodology for identifying Clean Units. Any unit that meets these qualifications shall be presumed to be a Clean Unit. Conversely, the opposite is not true. The reviewing authority shall not presume that a unit that does not meet the test is not a Clean Unit. The quality and number of determinations in the RBLC vary by different type of sources. The RBLC may not always identify all the types of control technology strategies that should qualify an emissions unit as a Clean Unit, or it may not provide a representative sample for making an appropriate determination. Therefore, even if you are unable to demonstrate that your emissions unit is a Clean Unit using this methodology, your reviewing authority shall not allow this outcome to prejudice its decision-making.

Accordingly, we are providing a second option for determining whether you qualify as a Clean Unit. If your emissions unit does not meet the emission limitation determined from the analysis of the RBLC described above (as appropriate for the area in which it is located), or if there is insufficient information in the RBLC to conduct the analysis, then you may still show, on a case-by-case basis, that your emissions unit will achieve a level of control that is ''substantially as effective'' as BACT or LAER, depending whether your emissions unit is in an attainment area or a nonattainment area. In an attainment area, your emissions unit must achieve a level of control that is ''substantially as effective'' as BACT. In a nonattainment area, your emissions unit must achieve a level of control that is ''substantially as effective'' as LAER. The reviewing authority will make a decision on whether a particular air pollution control technology (which includes pollution prevention or work practices) is ''substantially as effective'' as the BACT/LAER technology for a specific source on a case-by-case basis.

We are not promulgating specific requirements or performance criteria for satisfying the ''substantially as effective'' test, because we believe reviewing authorities are in the best position to determine whether in fact a particular air pollution control technology (which includes pollution prevention or work practices) is ''substantially as effective'' as the BACT/LAER technology for a specific source. The case-by-case determinations must meet the same air quality test as those units going through a BACT/LAER determination. Moreover, the public has opportunity for public review and comment on the ''substantially as effective'' decision. With these safeguards, we believe the ''substantially as effective'' test will ensure determinations that meet both the control technology and air quality tests, as well as allow sources to implement the controls that are best suited to their individual processes.

Under the second part of the test to determine whether your unit qualifies for Clean Unit status, you must demonstrate that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset.

4. Can an Emissions Unit That Applies No Emissions Control Technology Qualify as a Clean Unit?

In most cases, BACT/LAER will result in significant emissions decreases (such as 90 percent control for many VOC coating sources).[32] In some circumstances, however, the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using a control technology (add-on control, pollution prevention technique, or work practice). Under today's rules, you will not qualify as a Clean Unit in such circumstances. More specifically, today's rules also require you to make an investment to qualify initially as a Clean Unit. An investment includes any cost which would ordinarily qualify as a capital expense under the Internal Revenue Service's filing guidelines whether or not you actually choose to capitalize that cost. An investment also includes any cost you incur to change your emissions unit or process to implement a pollution prevention approach, including research expenses, or costs to retool or reformulate your emissions unit or process to accommodate an add-on control, pollution prevention approach, or work practice.

5. When Do the Major NSR Requirements Apply to Clean Units?

Once an emissions unit qualifies as a Clean Unit, it is subject to an alternative major NSR applicability test for calculating emissions increases for subsequent changes. As we discussed in section II of this preamble, we have codified our longstanding policy (for emissions units that are not Clean Units) that a major modification occurs if both of the following result from the modification: (1) A significant emissions increase following the physical or operational change; and (2) a significant net emissions increase from the major stationary source. The major NSR applicability test for Clean Units is a different process.

For Clean Units, you must first determine whether a project causes the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit. If it does, you lose Clean Unit status, and the project is subject to the applicability requirements as if the emissions unit were never a Clean Unit. If the project does not cause the need to change the emission limitations or work practice requirements in the permit which were established in conjunction with BACT, LAER, or Clean Unit determinations and any physical or operational characteristics that formed the basis for the BACT, LAER, or Clean Unit determination for a particular unit, then you maintain Clean Unit status, and no emissions increase is deemed to occur from the project for the purposes of major NSR. Once you have lost Clean Unit status, you can only re-qualify for Clean Unit status by going through the process that we describe in section V.C.9 of this preamble.

6. Can You Get Clean Unit Status for Controls That Have Already Been Installed?

As discussed in section V.C.3, emissions units that have been through major NSR permitting automatically qualify for Clean Unit status. This includes those emissions units that went through major NSR before promulgation of today's final rules. If an emissions unit automatically qualifies for Clean Unit status because it went through major NSR, its Clean Unit status is based on the BACT/LAER controls that went into service as a result of the major NSR review. That is, Clean Unit status is based on the BACT/LAER controls regardless of whether the actual process for designating Clean Unit status through title V occurs at some time after the controls went into service. However, Clean Unit status, and the ability to use the applicability process for Clean Units, does not begin until the Clean Unit effective date. We discuss the specific procedures for when Clean Unit status starts, when it ends, and how it is designated in sections V.C.7 through 9.

For emissions units that have not been through major NSR, our rules allow your reviewing authority to provide you with Clean Unit status for emissions control that you have already installed and operated. However, our final rules also limit the time frame under which your reviewing authority is allowed to make such determinations for Clean Unit status that is granted through a SIP-approved permitting process other than major NSR. Your reviewing authority will only be able to grant Clean Unit status for previously installed emissions controls if they were installed before the effective date of the program in your area. If the emissions unit's control technology is installed on or after the date that provisions for the Clean Unit applicability test are effective in your area, you must apply for Clean Unit status from your reviewing authority at the time the control technology is installed. As for emissions units that went through major NSR review, Clean Unit status for emissions units permitted through SIP-approved programs other than major NSR does not begin until the Clean Unit effective date.

If you are applying for retroactive Clean Unit status, today's final rules allow your reviewing authority to compare your emissions control level to the BACT or LAER level that would have applied at the time you began construction of your emissions unit. However, in some cases, such a comparability analysis may be difficult for you to demonstrate because of lack of sufficient information from which your reviewing authority can make a reasoned determination. If this is the case, then you will have to demonstrate that your emissions controls are comparable to a BACT or LAER limit from a subsequent or current date.

7. When Can I Begin To Use the Clean Unit Test?

The exact effective date depends on the circumstances of the individual emissions unit, as explained further below. As a general principle, however, the effective date for Clean Unit status can never be before the Clean Unit provision becomes effective in the relevant jurisdiction.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, the effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier. However, the effective date can be no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the SIP and become effective for the State in which the unit is located. That is, if the source had a major NSR permit and began operating before the Clean Unit provision becomes effective in the relevant jurisdiction, the effective date is the date the State or local agency begins authorizing Clean Unit status. As we noted earlier, if the emissions unit previously went through major NSR, it automatically qualifies as a Clean Unit. The original Clean Unit status would be based on the controls

[32] It is possible that a BACT/LAER analysis will not always result in the requirement of add-on controls at a source. In some situations, a reviewing authority may appropriately determine that the control technology that best represents BACT/LAER is a work practice, or a combination of work practices and add-on controls. As a result, a requirement to use work practices, or a combination of add-on controls and work practices, as an emissions control technology, could qualify an emissions unit for Clean Unit status, provided it meets the criteria established.

that were installed to meet major NSR. An additional investment at the time the original Clean Unit status becomes effective is not required.

For emissions units that re-qualify for Clean Unit status (see section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, the effective date is the date the new major NSR permit is issued.

If you obtain Clean Unit status from your State or local reviewing authority using a SIP-approved permitting process other than major NSR, the Clean Unit effective date is the later of the following dates: (1) The date that the State or local agency permit that designates the emissions unit as a Clean Unit is issued; and (2) the date that the emissions unit's air pollution control measures went into service. That is, if the controls went into service before the issuance date of the State or local agency permit that designates the unit as a Clean Unit, the Clean Unit effective date is the date that the permit is issued. As with units that have been through major NSR, additional investment is not required for the limited cases where there is a retroactive designation. If the issuance date of the State or local agency permit that designates the emissions unit as a Clean Unit is before the date the controls went into service (as would likely be the case for a unit that is new or modified after the State or local agency begins to authorize Clean Unit status), then the effective date of Clean Unit status is the date the controls went into service.

8. How Long Does Clean Unit Status Last?

In most cases, you may use the Clean Unit applicability test for a period of 10 years.[33] As a general principle, the Clean Unit expiration date can never be later than the date that is 10 years after the controls are brought into service.

For emissions units that automatically qualify for their original Clean Unit status because they have been through major NSR review, and for units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR review and implementing new control technology to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier. However, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

For emissions units that re-qualify for Clean Unit status (*see* section V.C.9) by going through major NSR using an existing control technology that continues to meet current-day BACT/LAER, Clean Unit status expires 10 years after the effective date. However, as noted above, Clean Unit status expires sooner if, at any time, the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

The expiration date for Clean Units that have not been through major NSR permitting depends on whether the owner or operator qualifies for Clean Unit status based on current BACT/LAER, or on BACT/LAER at the time the control technology was installed. If the owner or operator of a previously installed unit demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT/LAER requirements that applied at the time the control technology was installed, then Clean Unit status expires 10 years from the date that the control technology was installed. For all other emissions units (that is, previously installed units that are demonstrated to be comparable to current BACT/LAER, new units, and units that re-qualify as Clean Units), Clean Unit status expires 10 years from the effective date of the Clean Unit status. In addition, for all emissions units, Clean Unit status expires any time the owner or operator fails to comply with the provisions for maintaining Clean Unit status that are included in the final rules.

When your Clean Unit status expires, you are subject to the major NSR applicability test as if your emissions unit is not a Clean Unit. The permitted emissions levels established for the Clean Unit do not expire.

9. Can I Re-qualify for Clean Unit Status?

You may re-qualify for Clean Unit status after the status has expired or you have otherwise lost Clean Unit status, if you meet the conditions in our final regulations. As we stated before, we believe that once you have installed state-of-the-art emissions control, an additional major NSR review will generally not result in any additional emissions controls for a period of years after the original control technology determination is made. Also, the period for which any specific air pollution control technology (which includes pollution prevention or work practices) will continue to achieve the same level of control depends on many factors. As a practical matter, we have established a single time frame of 10 years for Clean Unit status, to provide simplicity in our final rules. However, for reasons we discuss in detail in section V.E.1 of this preamble, we determined that a reasonable average equipment life for a control technology is generally longer than 10 years. Certainly we want to encourage source owner/operators to install and maintain state-of-the-art control. We believe this is more likely when you can be assured that you can retain Clean Unit status for the useful life of the equipment, as long as air quality continues to be assured. The useful life of the equipment may extend beyond the original Clean Unit expiration date. Therefore, we are promulgating final regulations that allow you to apply to re-qualify for Clean Unit status.

To re-qualify for Clean Unit status, you would generally follow the same process that you used in first qualifying for Clean Unit status. However, we will not necessarily require you to meet an additional investment test to re-qualify for Clean Unit status for the same controls. That is, unless the controls used to establish Clean Unit status are no longer BACT/LAER or comparable, there will be no requirement for an investment to re-qualify for Clean Unit status.

You may re-qualify for Clean Unit status either by going through major NSR or by going through the alternative Clean Unit Test that we described in section V.C.3 of this preamble: (1) The air pollution control technology (which includes pollution prevention or work practices) must be comparable to BACT or LAER; and (2) the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. Regardless of which process you used to establish Clean Unit status initially, you may choose to re-qualify for Clean Unit status by going through major NSR or by going through the alternative two-part test.

Once you have submitted an application to re-qualify for Clean Unit status, the reviewing authority will make a determination concerning current BACT/LAER or comparable control technology. For example, suppose you had Clean Unit status for an emissions unit for which the controls

[33] As discussed in section III.E of today's preamble, we believe that 15 years represents a reasonable time period for designating a Clean Unit. However, we proposed and took comment on a 10-year period; therefore, we are finalizing today's rule with a 10-year duration. In a separate **Federal Register** notice we will be proposing to change this duration to 15 years.

went into service June 1, 1996, the permit application for Clean Unit re-qualification was submitted December 1, 2004, and the Clean Unit status expires June 1, 2006. In cases where the controls you installed in 1996 are still BACT/LAER or comparable when the reviewing authority makes the determination following your application submittal in 2004, the emissions unit can re-qualify for Clean Unit status based on the controls installed in 1996 if your emissions unit still meets all of the criteria for Clean Unit status. That is, in addition to the control technology review, the emissions unit must go through an air quality review and public participation.

A safeguard related to Clean Unit controls is that for re-qualifying for Clean Unit status when the emissions unit is located in a nonattainment area, the control determination must be LAER or comparable to LAER. If you previously received Clean Unit status based on the BACT level of control while the source was located in an attainment area and the attainment area becomes a nonattainment area by the time your Clean Unit status expires, the Clean Unit status for re-qualification must be based on controls that are LAER or comparable to LAER.

The air quality analysis for Clean Unit re-qualifications will be that of the path that you have chosen'major NSR, or comparable. As we discuss in detail in section V.C.3 of this preamble, for emissions units qualifying for Clean Unit status through the comparable test, you must show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We believe that the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process will ensure that Clean Units will continue to protect air quality throughout the 10-year re-qualification period. Moreover, any offset or mitigation requirements as a result of a previous major NSR determination will remain in force.

We expect that in many cases the controls used to initially establish Clean Unit status will still be operating efficiently and the Clean Unit status can be reestablished for an additional 10 years based on those controls. Suppose, however, you submitted an application to re-qualify for Clean Unit status and the reviewing authority determines that your existing controls do not meet the level of current BACT/LAER or comparable controls. In this case, you must install new or upgraded controls to re-qualify for Clean Unit status. You must go through the control technology determination, air quality review, and public participation requirements of the Clean Unit re-qualification process as described above.

10. What Terms and Conditions Must the Permit for my Clean Unit Contain?

Major NSR permits contain the emission limitations based on BACT/LAER, other permit terms and conditions that the reviewing authority identifies as representative of BACT/LAER (such as limits on hours of operation), and monitoring, recordkeeping and reporting requirements for the emissions unit. If you are qualifying for Clean Unit status through the major NSR review, your major NSR permit will have such terms and conditions. Likewise, any permit under a SIP-approved permitting process other than major NSR that designates an emissions unit as a Clean Unit must specify: (1) The source-specific allowable permit emission limitations, the exceedance of which, in combination with a significant net emissions increase, will trigger major NSR review; (2) other permit terms and conditions that the reviewing authority identifies as representative or comparable to BACT/LAER for your control technology (such as limits on operating parameters, etc.); (3) any conditions used as the basis for the control technology determinations (hours of operation, limits on raw materials, etc.); and (4) the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a ''clean'' level of emissions control is being achieved. Additional monitoring, recordkeeping, and reporting may be required to assure compliance under §§ 70.6(a)(3) or 70.6(c)(1) (that is, to assure compliance under title V).

The State and local agency permits establishing Clean Unit status must contain a statement designating the emissions unit as a Clean Unit. The State or local agency permit must also include general terms and conditions indicating the Clean Unit effective date and expiration date. Suppose the State or local agency permit has an effective date of May 5, 2006, and the controls will be installed after this date. The SIP permit would state that the effective date of the Clean Unit status is the date the controls go into service. The permit would also state that Clean Unit status will expire no later than May 5, 2016.

Your title V permit must include the Clean Unit status, as well as the effective and expiration dates of the Clean Unit status. Your title V permit must also include: the emission limitation(s) that reflect BACT/LAER or comparable control; other permit terms and conditions that the reviewing authority has determined represent BACT/LAER or comparable control (such as limits on hours of operation) and that ensure that air quality is protected; and the monitoring, recordkeeping, and reporting requirements necessary to demonstrate that a ''clean'' level of emissions control is being achieved.

11. How Will my Clean Unit Status be Incorporated Into my Title V Permit?

Clean Unit status and other permit terms and conditions must be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71, but no later than when the title V permit is renewed.

The title V permit must also contain the specific dates on which your Clean Unit status is effective and on which it expires. We are aware that the specific Clean Unit effective and expiration dates will frequently not be determined at the time that Clean Unit status is established. Therefore, the initial title V permit action that incorporates Clean Unit status and other permit terms and conditions may need to state the Clean Unit effective and expiration dates in general terms. For example, for units that have been through major NSR, the initial title V permit might state that the expiration date is the earlier of the following dates: the date 10 years after (1) the Clean Unit's effective date, or (2) the date the equipment went into service. The permit does not have to include the specific Clean Unit effective and expiration dates where they cannot be determined at the time of initial incorporation, such as would be the case when the Clean Unit has yet to be constructed. Furthermore, in these instances, we are not requiring that the title V permit be modified to incorporate the specific Clean Unit effective and expiration dates until the next permit renewal, reopening, or modification after such dates are known.

As soon as the specific Clean Unit effective and expiration dates are known, the source must report them to the reviewing authority. The specific Clean Unit effective and expiration dates must then be incorporated into the title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal. However, it is not necessary to amend the SIP-approved permit to incorporate the specific Clean Unit effective and expiration dates, as long as these dates are incorporated into the title V permit at the next renewal. If you wish to incorporate the Clean Unit effective and expiration dates into the SIP permit, a title V modification would be required.

While the title V permit contains the Clean Unit permit terms and conditions, we want to emphasize that any changes to Clean Unit permit terms and conditions (other than incorporating the specific Clean Unit effective and expiration dates) must first be made through a SIP-approved permitting process that provides for public review and opportunity for comment. Any such changes would be incorporated into the title V permit in the manner described above.

12. Can a Clean Unit Be Used in a Netting Analysis?

Generally, for an emissions unit that has Clean Unit status because it has gone through major NSR permitting, you must not include emissions changes at the Clean Unit in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of Clean Unit status or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for the purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets. We are allowing the credit to be computed in this manner because the owner or operator has already obtained an actual emissions-based offset for the emissions up to the Clean Unit emission limitations. By the owner/operator's accepting a federally enforceable emission limitation below this level, these offsets are now available to create additional actual emissions reductions.

The final rules are similar for emissions units that are designated as Clean Units in a SIP-approved permitting process other than major NSR. You must not include emissions changes that occur at such units in a netting analysis, or use them for generating offsets, unless the emissions changes occur and you use them for these purposes before the effective date of the SIP requirements adopted to implement the Clean Units or after Clean Unit status expires. However, if you reduce emissions from the Clean Unit below the level that qualified the unit as a Clean Unit, you may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation, if such reductions are surplus, quantifiable, permanent, and federally enforceable (for purposes of generating offsets) and enforceable as a practical matter (for purposes of determining creditable net emissions increases and decreases). Such credits may be used for netting or as offsets.

13. How Does Clean Unit Status Apply When There Are Multiple Pollutants?

Clean Unit status is pollutant-specific and may not be granted for more than one pollutant, except in cases where a group of pollutants is characterized as a single pollutant, such as VOCs. You may, however, qualify for simultaneous Clean Unit status for other pollutants at those emissions units that are sufficiently controlled to independently qualify as ''clean'' for each pollutant. For units applying for Clean Unit status and that do not already have a major NSR permit, the reviewing authority must specify the pollutants for which Clean Unit status applies as part of the permitting process establishing Clean Unit status.

D. Legal Basis for the Clean Unit Test

As discussed above, the Clean Unit applicability test would provide an alternative emissions test for determining if a significant increase in emissions has occurred after a physical change or change in the method of operation at units that are designated as ''clean.'' We believe that we have the authority to allow these specific types of units to use a different applicability test.

The CAA is silent on whether increases in emissions for purposes of determining whether a physical or operational change constitutes a modification must be measured in terms of actual emissions, potential emissions, or some other currency. We believe that it is a reasonable interpretation of the CAA to determine applicability of the major NSR program for units qualifying as Clean Units in terms of the emission limitations or work practice requirements in the permit, and that this interpretation is consistent with the statutory purposes of NSR.

The PSD permitting program has 5 key elements: (1) Control technology review; (2) air quality review; (3) monitoring requirements; (4) information on the source; and (5) procedures for processing applications, including public notice and the opportunity for comment. A new major source or major modification in an attainment area must go through PSD permitting to become a Clean Unit. That process would have had to include the elements listed above. CAA section 165.

Similarly, the CAA requires new major sources or major modifications undertaken in nonattainment areas to obtain permits that require them to meet LAER and to obtain offsetting emissions reductions. CAA section 173. In order to be designated a Clean Unit, a major source or modification in a nonattainment area would have had to have gone through major NSR permitting review in the last 10 years.

We believe that units that have undergone minor source permitting in a manner that fulfills the statutory purposes of major NSR—either because a State's minor NSR program already contains equivalent provisions or because the existing program is enhanced for the purpose of allowing the reviewing authority to satisfy Clean Unit criteria—also will have satisfied the requirements of the CAA in a manner sufficient to justify Clean Unit status. As we have discussed in section V.C of this preamble, to obtain Clean Unit status through a minor NSR program, that process must include a requirement for public participation. Furthermore, emissions units that are designated as Clean Units through SIP-approved minor NSR programs must satisfy an air quality test. You must provide information demonstrating that you will not cause or contribute to a NAAQS or PSD increment violation or adverse impact on an AQRV in a Federal Class I area. If your emissions unit has already been permitted under minor NSR or another SIP-approved permitting program, you may have already satisfied the second part of this test. If not, consistent with the requirements in sections 165(a)(3) and 173(a) of the CAA, you will be required to show that the allowable emissions will not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. For areas that do not already attain the NAAQS, the source would be required to show that the emissions for the unit have been previously offset, or the reviewing authority will have to show that these emissions will not interfere with the State's ability to achieve attainment.

For Clean Units that have emission limitations and/or work practice requirements established through programs that fulfill relevant major NSR statutory requirements, we believe that the alternative way to estimate emissions increases to evaluate applicability set forth under the Clean Unit Test is appropriate and consistent with Congress's intent. A project at a Clean Unit that would require a revision to the emission limitations or work practice requirements established through permitting programs that meet the requirements of the Act, or that would alter any physical or operational characteristics that formed the basis for the permitting action, must go through a new permitting process. The reviewing authority must have already required state-of-the-art pollution control technology (or, through an investment, its pollution prevention or work practice equivalent), conducted the required air quality analyses based on the emissions level in the permit, and provided the public with an appropriate opportunity to comment on that level of emissions and air quality impact. Therefore, we believe that allowing an alternative means of evaluating applicability based on a revised emissions test for this category of unit is consistent with the CAA.

E. Summary of Major Comments and Responses

Although a few commenters categorically oppose the Clean Unit Test, most commenters support the concept. Practically all commenters oppose some aspect of the test or request that the test be clarified. Below are the major comments and our responses.

1. How Long Should You Be Eligible for the Clean Unit Applicability Test?

We received numerous comments on the duration of Clean Unit status. In the proposal, we suggested a 10-year duration and asked for comments regarding this period. We received comments supporting various lengths of time from 2 to 20 years. Although some commenters support a 10-year duration, other commenters oppose it.

Many commenters believe that 10 years is too short for Clean Unit status. These commenters argue that BACT/LAER technologies accomplish substantial pollutant removals, and that the cost of a slight increase in pollutant removal is usually significant. These commenters urge us to establish a Clean Unit status duration that comports with the useful life of the control equipment, which would enable you to recover the costs of installing the pollution control technology. They believe that you should be able to recoup the investments in pollution control before being forced to abandon that technology and pay again for newer technology. Some commenters request that a presumptive life of 20 years be awarded to Clean Units, which is approximately how long the control equipment should be effective.

Some commenters believe that 10 years would be too long, because they believe that advances in control technology occur more rapidly. A 10-year duration would allow old, less effective technologies to be the basis of immunity from the NSR program. These commenters are particularly concerned about the 10-year duration for BACT/LAER determinations that were based on no controls.

We believe that we have discretion to determine the appropriate period for which you should be eligible for the Clean Unit applicability test. As a policy matter, we believe that this time period should reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. As a practical matter, we realize that the ''ideal'' time frame will vary by emissions control technology and by pollutant; however, we believe using a single time frame will provide simplicity in our final rules.

To determine an average life expectancy for a variety of control technologies, we relied on the guidelines for equipment life for 9 commonly used emissions control technologies published in ''Estimating Costs of Air Pollution Control Systems, Part II, Factors for Estimating Capital and Operating Costs.''[34] Using the average of the low, average, and high values, we determined that a reasonable average equipment life for a control technology is equal to 15 years.

We then looked at the incremental improvement in control technology over time. We found that the evolution of pollution control equipment over time is dominated by innovation, rather than invention. In other words, the change in design and capacity for any given device type occurs infrequently as a series of marginal improvements over the preceding design. Consequently, the marginal improvement in pollution abatement one can expect between generations of the same type of device is also very small—too small to justify the cost of an entirely new unit. For example, flue gas desulfurization (FGD) units have been used in the United States for about 20 years, and were used in Japan and Germany for 10 years before that. During the early 1980's, a typical FGD system removed about 90 percent of the sulfur from a flue gas stream. Today, modern FGD systems typically average 95 to 99 percent removal efficiency—less than a 10 percent improvement in 20 years.

We also evaluated, from a cost-per-ton basis, whether the marginal improvement in removal efficiency is too expensive. Again, we considered the FGD example. From an actual NSR determination for a coal-fired electrical generating unit in the Midwest, the installation of an FGD system in 1985 would have cost $189 million and had a removal efficiency of 90 percent (76,500 tons of sulfur per year). The identical boiler in 2001 would use an FGD system with a 95 percent efficiency, costing $285 million, and removing 80,750 tpy, an additional 4,250 tons. The additional cost for the improved design for the 2001 installation (including the retrofit and upgrade of existing components and the new cost of larger pumps and other auxiliary equipment) would have been more than $100 million, or greater than $24,000 per ton. Consequently, from an efficiency standpoint, requiring an upgrade on this unit to BACT or LAER levels would not have been economical.

After reviewing all of this information, we determined that a 15-year period represents a reasonable and appropriate time frame during which you should be allowed to use your permitted allowable emissions to determine whether an increase triggers major NSR review. However, we proposed and took comment on a 10-year duration. Therefore, today we are finalizing a single time frame of 10 years that applies to all types of emissions control technologies and all types of pollutants. Because we believe that 15 years represents a reasonable time frame, we will be proposing a 15-year duration for Clean Unit status. After considering any public comments on a 15-year duration for Clean Unit status, we may amend today's final regulations.

We believe it is beneficial to allow emissions units using pollution prevention techniques or work practices to qualify for Clean Unit status where those units meet certain criteria. In some cases (coating operations, for example), pollution prevention techniques or work practices are state-of-the-art pollution control, and either

[34] Vatavuk, William, ''Part II, Factors for Estimating Capital and Operating Costs,'' *Chemical Engineering*, Nov. 3, 1980.

there would not be an improvement in pollution control if the unit were required to install add-on controls or the incremental cost effectiveness of the add-on control installation would be too high for it to qualify as BACT. In other cases, the most stringent control is based on add-on control and pollution prevention. Therefore, under many circumstances, we believe that pollution prevention techniques and work practices can be implemented to achieve a level of emissions reductions comparable to that achieved by BACT/LAER add-on controls. Also, initiation of a pollution prevention technique or a work practice can require a substantial investment in research to retool or reformulate your operations. Thus, we do not believe that a blanket exclusion from Clean Unit status is appropriate for emissions units that are controlled with pollution control techniques.

Implementation of pollution prevention approaches and work practices usually requires research, followed by some retooling or reformulation of a process line or unit operation. As part of this retooling or reformulation, some equipment has to be purchased up front (for example, sniffers for leak detection and repair operations, improved process control consoles and/or software for recycle streams, initial modeling for combustion optimization systems). This equipment purchase or initial modeling involves a one-time investment; hence, there is an investment associated with pollution prevention or work practice implementation. Researching the application of an approach also qualifies as an investment for these purposes.

We received comment from a number of commenters who are concerned about Clean Unit status when BACT/LAER determinations are based on no control. As these commenters note, ''no controls'' does not equate to a well-controlled emissions unit. We agree with these commenters, and today's final rules clarify that Clean Unit status can be based on add-on control, pollution prevention techniques, work practices, or a combination of them. We recognize that there are some circumstances when the outcome of a reviewing authority's BACT or LAER determination may result in an emission limitation that you will meet without using an air pollution control technology (which includes pollution prevention or work practices). We believe that such emissions units should not qualify as Clean Units, because they fail the very premise under which we established the Clean Unit applicability test. That is, there is no period of time in which we can reach a balance between the unit's useful emissions control equipment life and the time frame in which additional major NSR review is likely to result in no added environmental benefit. Source categories that currently have few or no control technology options are likely to be the categories that will experience a rapid advancement in emissions control technology over a short period of time. Accordingly, today's final rules contain two limitations on use of the Clean Unit applicability test. You may not use the Clean Unit applicability test for any emissions unit that is not using an air pollution control technology (which includes pollution prevention or work practices) and for which you have not made an investment to control emissions.

2. Does the Clean Unit Applicability Test Measure the Increase in Maximum Hourly Potential Emissions?

We proposed that the Clean Unit Test would continue to apply as long as the emissions unit's maximum hourly potential emissions did not increase. The baseline for the maximum hourly potential emissions rate could be established at any time in the 6 months before the activity or project that increases emissions. Almost all commenters oppose basing the Clean Unit Test on the hourly PTE, as well as the 6-month period for setting the emissions rate. Some commenters argue that an hourly PTE test is not environmentally protective enough. One commenter notes that we were inappropriately using the applicability test under the NSPS as the applicability test for major NSR, which should be based on tpy. Many commenters view the hourly PTE test as so restrictive that few sources would take advantage of the Clean Unit Test. These commenters believe that the hourly emissions rate obscures the real basis for Clean Unit status, which is the add-on control efficiency.

We agree with the commenters who maintain that Clean Unit status should be based on the emissions level achievable through the use of control technologies. As these commenters note, once an emissions level has been determined based on BACT/LAER, it is unlikely that additional review would result in a more stringent level of control. As a result, we are not finalizing the Clean Unit Test as proposed with the hourly PTE test. Instead, today's final rules for Clean Units are based on reduction of air pollution through the use of control technology (which includes pollution prevention or work practices) that meet both the following requirements. First, the control technology achieves a BACT/LAER level of emissions reduction as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for Clean Unit status if the BACT/LAER determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type. Second, the owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

By adopting this approach, we are allowing the reviewing authority to decide the appropriate emission limitations or work practice requirements that will be used to obtain and maintain Clean Unit status. If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements that form the basis for Clean Unit status, the emissions unit remains a Clean Unit. On the other hand, if the project causes the need for such change to the emission limitations or work practice requirements, the emissions unit loses Clean Unit status and is subject to the applicability requirements of major NSR.

3. What Kind of Changes Are Allowed Under Clean Unit Status?

It is not our intention to limit increases in emissions unit capacity as long as emissions are under the source-specific allowable levels and the increase is within the capacity for which you obtained approval when applying for Clean Unit status. Incremental improvements to existing units are acceptable. However, complete changes to emissions units making them into completely different units than were originally permitted are not acceptable. For example, switching to a smaller but more polluting process than originally permitted may trigger stricter BACT/LAER requirements, even at the same annual emissions rate, since higher percentage removal rates and lower costs would be possible at higher concentrations.

We expect that changes such as, but not limited to, increasing production to permitted levels, reconfiguring the process, changing process chemicals if consistent with the original Clean Unit application, replacing components, replacing catalysts, or adding other controls, or other changes would be allowable for Clean Units. In no instances are we authorizing violations of any existing permit conditions or other applicable requirements that may apply to the Clean Unit. You may not reconstruct a Clean Unit under an existing Clean Unit status.

4. Does the Clean Unit Applicability Test Apply to Units That Have Not Gone Through a Major NSR Permitting Review?

In 1996, we proposed that reviewing authorities submit their minor source permit decisions for us to determine whether the emission limitations were comparable to BACT or LAER. Commenters generally support allowing units permitted through minor NSR programs to qualify for Clean Unit status. These commenters believe State and local agencies are well-equipped to make control technology determinations. A few commenters are concerned that control technology determinations made under minor NSR programs do not always require adequate air quality review or opportunity for public comment and review. They maintain that these program elements are essential for making control technology determinations that are equivalent to BACT/LAER.

We also received comments on allowing Clean Unit status for emissions units that have not gone through either major or minor NSR, such as those that decrease emissions to meet other requirements under the Act. These comments are mixed. A few commenters support this option. Others believe it makes no sense to extend the status to units that had not had a recent control technology determination, particularly considering the burden the review would place on reviewing authorities.

We agree that control technology determinations made by State and local agencies can be comparable to BACT/LAER, regardless of the purpose for which the control technology decision is made. However, we also agree with those commenters who believe a thorough analysis is necessary to ensure that air quality is protected. Moreover, we agree that a control technology determination is incomplete unless it has been through public review.

Therefore, today we are promulgating regulations that allow emissions units that have not had a BACT/LAER determination to qualify for Clean Unit status, if they are permitted under a SIP-approved permitting program that provides for public notice of the proposed determination and opportunity for public comment to determine whether you should qualify as a Clean Unit.

5. Does Clean Unit Status Apply to Units That Have RACT or MACT Limits?

A number of commenters maintain that emission limitations based on RACT and MACT achieve control comparable to those based on BACT and LAER. These commenters therefore believe Clean Unit status should be available for emissions units with RACT or MACT limits. However, other commenters agree with us that RACT and MACT limits should not automatically be considered equivalent to BACT/LAER limits.

We are maintaining our position in the proposal rule that Clean Unit status does not presumptively apply to units with limits based on RACT or MACT. However, when you believe a specific RACT or MACT limit is comparable to BACT/LAER, you may choose to use a SIP-approved permitting process to try to obtain Clean Unit status.

6. How Should We Determine Whether a Control Technology Is Comparable to BACT or LAER?

We proposed two methods for determining that control technology was comparable to BACT/LAER—average of the level of control for the last 3 years, and percent control. None of the commenters support using the average emissions rates to determine comparability. The commenters believe that in some cases this approach could lead to skewed results, or that the average control determination can differ substantially from the most recent determination. The commenters suggested that EPA consider all technologies required to be considered in a BACT/LAER determination, not just those listed in the RBLC. The commenters also say that it is not acceptable to call an uncontrolled unit a ''clean'' unit, when the Clean Unit Test is meant for companies that have taken the effort and expense to install controls or low emitting equipment. Although a few commenters support using percent control, several commenters oppose it. They maintain that defining control levels based on a certain percentage derived from BACT or LAER for equivalent sources is not simple and would require the frequent collection and maintenance of large quantities of information.

Based on the public comments on our two proposed methods, we have decided to develop a modified version of the proposed averaging method for determining when an air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER. You can make a showing that the air pollution control technology (which includes pollution prevention or work practices) is comparable to BACT/LAER in one of two ways: (1) by comparing your emissions unit's control level to BACT/LAER determinations for other similar sources in the RBLC; or (2) by making a case-by-case demonstration that your emissions control is ''substantially as effective'' as BACT or LAER.

Under the first approach, we have developed slightly different approaches for sources located in attainment and nonattainment areas. For those emissions units located in attainment areas, the emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. To address the commenters' concerns regarding other BACT/LAER determinations that might not be in the RBLC, we have included a provision that allows the reviewing authority to also compare this presumption to any additional BACT or LAER determinations of which it is aware, and to consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

For sources in nonattainment areas, the emissions unit's control technology is presumed to be comparable to LAER if it achieves an emission limitation that is at least as stringent as any one of the 5 best-performing similar sources for which a LAER determination has been made within the preceding 5 years, and for which information has been entered into the RBLC. As is the case for units in attainment areas, the reviewing authority shall also compare this presumption to any additional LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to LAER is correct.

The second approach, the ''substantially as effective'' test, avoids a ''one-size-fits-all'' approach that could preclude some well-controlled sources from benefitting from the Clean Unit Test simply because there is insufficient information in the RBLC or because they are using an innovative approach to emissions control. This provision will allow you to use alternative controls as long as they achieve comparable control and air quality results. We believe that the reviewing authority is in the best position to judge whether a particular control technology achieves an emissions control level that is comparable to BACT or LAER for a specific application, as well as to assure that air quality impacts have been accounted for. Thus, rather than requiring the reviewing authority to submit its permit decisions to us for approval as a comparable technology, our final rules allow the reviewing authority the ability to make this determination after the public comment process.

7. Can Clean Unit Status Be Made Using the Title V Permitting Process?

We proposed that for sources that had not undergone major NSR, Clean Unit status would occur as part of the title V permitting process. Although a few commenters support this concept, several State and local agency commenters strongly disagree. These commenters believe that title V is an appropriate mechanism for documenting Clean Units, but that the process for certifying sources should be separate from title V to avoid delays in title V permitting.

We agree with these commenters, and today are promulgating provisions that an emissions unit may be designated as a Clean Unit once it has gone through major NSR or another SIP-approved permitting program that provides for public notice and opportunity for comment. This allows the reviewing authority the flexibility to use the permitting process that it believes is most appropriate to make a Clean Unit status determination. However, once Clean Unit status has been established through a SIP-approved permitting program, it must be incorporated into the title V permit. *See* section V.C.7 for a discussion of this process.

VI. Pollution Control Projects

A. Description and Purpose of This Action

Our policy is to promote pollution control and prevention projects whenever possible. Today we are finalizing a rule provision that would exclude from major NSR permitting requirements certain work practices and the installation of qualifying pollution control and pollution prevention projects. With these provisions, we are removing a regulatory disincentive that might otherwise prevent industry from undertaking pollution control and prevention measures that result in a net environmental benefit. The ''Pollution Control Project Exclusion'' (or ''PCP Exclusion'') will allow the installation of certain projects that result in net overall environmental benefits to avoid the permitting requirements of major NSR for their collateral emissions increases that exceed the significant level. This action was proposed on July 23, 1996, and closely paralleled our existing policy memorandum [35] which, in effect, enabled a control project exclusion for EUSGUs which was implemented under the electric utility-specific NSR rule (*see* 57 FR 32314, hereinafter ''WEPCO PCP Exclusion'') to apply to all types of sources, and enabled qualifying pollution prevention projects to apply for an exclusion as well. This action will replace both the WEPCO PCP Exclusion and the July 1, 1994 policy guidance with a single, comprehensive NSR exclusion for all types of qualifying PCPs—including add-on controls, switches to less polluting fuels, work practices, and pollution prevention projects. Morever, this final rule will minimize procedural delays in getting a PCP approved, while ensuring appropriate environmental protection.

We define a PCP as an activity, set of work practices, or project at an existing emissions unit that reduces emissions of air pollution from the unit. The PCP Exclusion may be sought when a project is installed at an existing source where it reduces the emissions rate of one air pollutant while causing an increase in emissions of a different, ''collateral'' pollutant. A common example of such a project is installation of a thermal incinerator, which forms NO_X as a collateral pollutant while reducing VOC emissions. For evaluating the environmental impact of a collateral emissions increase, the source and reviewing authority will assess the difference between the emissions unit's post-change actual emissions and its pre-change baseline actual emissions. This test is discussed in section II of today's preamble. That increase is then weighed against the emissions decrease of the primary pollutant to determine whether the PCP, as a whole, provides an environmental benefit. The source and reviewing authority also must ensure that the change does not cause or contribute to an air quality violation, that no ERCs are generated (through initial application of the PCP), and that any significant emissions increase of a nonattainment pollutant is accounted for with acceptable offsets or SIP measures. In performing the air quality analysis under this provision, the procedures established for conducting air quality analysis in conjunction with NSR permitting will be used.

This rule excludes the installation of qualifying PCPs—including add-on control devices, raw material substitutions, work practices, process changes and other pollution prevention strategies—from the definition of ''physical or operational change'' within the definition of major modification in our Federal regulations (*e.g.,* § 52.21). We are also requiring that States adopt the same exclusion in their NSR programs.

The decision to make codifying changes to the existing WEPCO PCP Exclusion and the July 1, 1994 policy guidance draws largely from recommendations of the CAAAC Subcommittee on NSR Reform. The members of the Subcommittee included representatives of State and Federal regulatory agencies, Federal natural resource managers, industry, and environmental and public health interest groups. The Subcommittee's recommendations reflected the consensus of this balanced group of stakeholders.

B. What We Proposed and How Today's Action Compares To It

Our proposed PCP Exclusion provisions essentially restated the July 1, 1994 policy guidance, and incorporated a ''primary purpose'' test as an initial hurdle for candidate PCPs. The ''primary purpose'' test would have limited the exclusion to those projects whose primary function is to reduce air pollution. The proposal, like the previous PCP Exclusion rule and policy guidance, maintained that the exclusion was not applicable to air pollution controls and emissions associated with the construction of a new emissions unit, nor to the replacement or reconstruction of an entire existing emissions unit with a newer or different one. In addition, the fabrication, manufacture, or production of pollution control/prevention equipment and inherently less polluting fuels or raw materials would not, in and of themselves, qualify as a PCP. We also incorporated two safeguards that were taken directly from the WEPCO PCP Exclusion and the July 1, 1994 policy

[35] July 1, 1994 memorandum from John S. Seitz, Director, OAQPS, ''Pollution Control Projects and New Source Review (NSR) Applicability'' and hereinafter referred to as the ''July 1, 1994 policy guidance.''

ED_001598_00027467

guidance. First, the reviewing authority would be required to determine that the PCP is ''environmentally beneficial.'' A second safeguard from our proposal would direct reviewing authorities to evaluate the air quality impacts of a proposed PCP and ensure that it does not cause or contribute to a NAAQS or PSD increment violation, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public.

We proposed specific add-on control technologies that would be considered presumptively ''environmentally beneficial'' based on their proven history of positive environmental impact. The proposal also allowed for fuel switches to less polluting fuels and substitutions to less potent ozone depleting substances (ODS) to be presumptively environmentally beneficial projects. For other pollution prevention projects and new add-on control technologies to qualify as a PCP, the proposal required the reviewing authority to determine that the project was environmentally beneficial and, additionally for new add-on control devices, that they be ''demonstrated in practice.''

We received comments on every key aspect of the proposed PCP Exclusion. Although most parties support the PCP Exclusion, their suggestions regarding implementation of the exclusion vary considerably. Industry commenters generally desire maximum flexibility, and suggest extending the exclusion to cross-media control projects, limiting the ''environmentally beneficial'' and ''primary purpose'' requirements, allowing for the generation of ERCs from PCPs, and broadening which pollution prevention projects qualified. Other commenters, including State agencies and environmental organizations, generally favor a more restrictive approach that involves more agency oversight and creates more enforceable mechanisms to ensure that the exclusion would not be abused. All comments are specifically addressed in the Technical Support Document.

Today's rule revises the proposed PCP Exclusion in several ways, including the following.

• Eliminating the ''primary purpose'' requirement.
• Expanding the list of presumptively environmentally beneficial projects to include additional control technologies and strategies.
• Enabling projects that otherwise are PCPs and result in utilization increases to qualify for the exclusion.
• Using an actual-to-projected-actual format for determining emissions changes for all source categories to demonstrate net environmental benefit supplemented by air quality analysis under certain circumstances, regardless of their projected emissions increases resulting from utilization.
• Clarifying that the replacement, reconstruction, or modification of an existing emissions control technology could qualify for the exclusion.
• Detailing the calculations for determining whether a switch to a different ODS is environmentally beneficial.
• Changing the visibility component of the air quality analysis to ''an air quality related value (such as visibility) that has been identified for a Federal Class I area by a FLM, and for which information is available to the general public''.
• Identifying which fuel switches are presumed ''inherently less polluting''.
• Enabling work practice standards to qualify for the exclusion.
• Clarifying that modeling for air quality impacts analyses may use projected actual emissions.
• Detailing proper noticing requirements for listed projects to use this exclusion.
• Describing in detail the process for granting the PCP Exclusion for non-listed control technologies and pollution prevention strategies.
• Disqualifying projects that cannot secure acceptable offsetting emissions reductions or SIP measures for PCPs resulting in a significant net increase of a nonattainment pollutant.
• Disallowing generation of netting and offset credits from the initial application of PCPs that qualify for this exclusion.
• Clarifying that non-air pollution impacts will not be considered in the ''environmentally beneficial'' determination.

By today's action we are superseding the PCP regulatory exclusion that applied only to EUSGUs. Today's action covers all types of sources, including EUSGUs. The new, broader PCP Exclusion will ensure equitable treatment of all source categories and remove any disincentive for companies that wish to install pollution control and pollution prevention projects, to the extent allowed by the CAA. Thus, owners or operators of EUSGUs who want a PCP Exclusion may, like any other source category, use the expanded definition of ''pollution control project,'' which includes the lengthened list of environmentally acceptable control devices. Despite today's rule revisions addressing a broader array of pollution control and pollution prevention projects at a larger variety of sources, we feel that the rule's procedures are less complex than and are clearer than the WEPCO PCP Exclusion and the July 1, 1994 policy guidance. We are satisfied that the final PCP Exclusion best achieves the goals of minimizing regulatory burden and reducing procedural delays for projects that ensure net overall environmental protection.

1. Applicability

a. *What types of projects may qualify for the PCP Exclusion?*

In the WEPCO PCP Exclusion, we found that installation of add-on emissions control projects, switches to less polluting fuels, and certain clean coal demonstration projects could be PCPs, ''unless the project renders the unit less environmentally beneficial.'' 57 FR 32319. Today's rule affirms that these types of projects are appropriate candidates for the exclusion, and it expands the types of projects that can qualify to include installation of other control devices that were not previously listed in the regulations, as well as work practice standards and switches to less potent quantities of ODS. Some of the control technologies (for example, oxidation/absorption catalyst and biofiltration) listed in today's revisions were either not well known or not demonstrated in practice as of the release of the WEPCO PCP Exclusion and the July 1, 1994 policy guidance exclusion; consequently, today's rule brings the list of approved PCPs up to date.

We believe that the overall net impact of installing and operating the listed add-on control systems is environmentally beneficial and that such projects are desirable from an environmental perspective. The add-on controls in the approved list historically have been applied to many different kinds of sources to reduce emissions. They have been consistently used because it is generally understood that, from an overall environmental perspective, these controls are effective in reducing emissions when they are applied to existing plants in a manner consistent with standard and reasonable practices. Certain pollution prevention projects—for example, fuel switches and low-NO_X burners—are also presumed to be environmentally beneficial when properly applied. Consequently, as part of the exclusion for PCPs, we do not require a case-by-case ''environmentally beneficial'' demonstration for the ''listed'' PCPs, as long as they are properly applied and site-specific factors do not indicate that their application would be environmentally harmful. Thus, the ''environmentally beneficial'' presumption created by the list may be rebutted. For companies wishing to install and operate non-listed PCPs, however, the process is more rigorous. In these cases, the reviewing authority first must consider case-specific factors to determine whether the non-listed project results in a net environmental benefit and then must provide an opportunity for, and respond to, public notice and comment before approving the project as a PCP.

b. Why does the PCP Exclusion not apply to greenfield sources?

Today's rule restricts applicability of the PCP Exclusion to physical changes being made at existing sources. Installing or implementing a project on an existing source is more likely to improve the environment than is the construction of a new source, since one can reasonably expect a PCP to reduce overall emissions, barring a considerable utilization increase. New sources, however, introduce new emissions to the air without reducing existing emissions, and consequently should be as clean as possible. Furthermore, new emissions units are among the major capital investments in industrial equipment, which are the very types of projects that Congress intended to address in the NSR provisions when such projects result in an overall emissions increase from the major stationary source. Thus, when emissions from a new source exceed the significant level, they are subject to NSR, and all emissions that are generated from the new project should be addressed in the major NSR permit evaluation for the major stationary source.

c. Does the PCP Exclusion apply to rebuilt or upgraded control devices?

We are clarifying in today's rule that upgrading or replacing existing emissions control equipment with a more effective emissions control project can qualify for the PCP Exclusion. However, the new PCP would have to result in a level of control more stringent than the original control equipment, in terms of emissions rate or output-based emissions rate, such as upgrading a scrubber to increase removal efficiency. Another example that would qualify is a control device that achieves an emissions reduction equivalent to that of the original device, but is more energy efficient. An example of this is the conversion of a thermal oxidizer to a catalytic oxidizer. As long as the catalytic oxidizer achieved emissions control equivalent to that of the thermal oxidizer, it would qualify for a PCP Exclusion since it reduces energy use.

2. Environmental Benefits

a. *What projects do we presume to be environmentally beneficial?*

Commenters recommend that we expand the list of presumptively environmentally beneficial projects to include other add-on control technologies that are commonly used to reduce emissions at major stationary sources. We agree with this recommendation and have expanded the list of presumptively environmentally beneficial PCPs accordingly in today's rule.

We presume the projects listed in Table 2 are environmentally beneficial. We based our decision to add certain projects to the list on two criteria: (1) The PCP is ''demonstrated in practice''; and (2) its overall effectiveness in reducing emissions of the primary pollutant(s) when balanced against its potential for emissions increases of collateral pollutant(s).

TABLE 2.—ENVIRONMENTALLY BENEFICIAL POLLUTION CONTROL PROJECTS

Control device/PCP	Pollutant controlled
Conventional & advanced flue gas desulfurization.	SO_2
Sorbent injection	
Electrostatic precipitators	Particulates and other pollutants.
Baghouses	
High efficiency multiclones	
Scrubbers	
Flue gas recirculation	NO_X
Low-NO_X burners or combustors	
Selective non-catalytic reduction	
Selective catalytic reduction	
Low emission combustion (for internal combustion engines)	
oxidation/absorption catalyst (e.g., $SCONO_X$ ™)	
Regenerative thermal oxidizers	VOC and HAP.
Catalytic oxidizers	
Thermal incinerators	
Hydrocarbon combustion flares [36]	
Condensers	
Absorbers & adsorbers	
Biofiltration	
Floating roofs (for storage vessels)	

[36] For the purposes of these rules, ''Hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including use of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions from waste streams comprised predominantly of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

Other presumed environmentally beneficial PCPs include activities or projects undertaken to accommodate: (1) switching to different ODS with a less damaging ozone-depleting effect (factoring in its ozone depletion potential and projected usage); and (2) switching to an inherently less polluting fuel, to be limited to the following.

- Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel. (that is, from a higher sulfur content #2 fuel, or from #6 fuel, to CA 0.05 percent sulfur #2 diesel)
- Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal.
- Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood
- Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content)
- Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content)

We are presuming that the application of a PCP listed above is environmentally beneficial and would be eligible for a PCP Exclusion. This presumption is premised on an understanding that you will design and operate the controls in a manner that is consistent with proper industry, engineering, and reasonable practices, and that you minimize increases in collateral pollutants within the physical configuration and operational standards usually associated with the emissions control device or strategy. You will be required to certify that this is true in the notification you send your reviewing authority.

As stated before, the ''environmentally beneficial'' determination is a presumption, so it can be rebutted in cases in which a reviewing authority determines that a particular proposed PCP project would not be environmentally beneficial. Also, this presumption does not apply when: (1) The PCP is not designed, operated, or maintained in a manner consistent with standard and reasonable practices; (2) the collateral pollutant emissions increases are not minimized within the physical configuration and operational standards usually associated with the emissions control device or strategy; or (3) the unit will be less environmentally beneficial. Also, when a reviewing authority determines that an otherwise listed project would not be constructed and operated consistent with standard practices, it may rebut the ''environmentally beneficial'' presumption for that application of the technology.

Finally, it should be noted that commenters on the proposed rule list several examples of specific projects they believe we should add to the list of presumptively environmentally beneficial projects. However, some of these suggested PCP scenarios would never trigger NSR because there would not be a significant increase in emissions, from either the collateral or primary pollutant. For example, one commenter says we should consider the termination or decommissioning of an emissions unit an environmentally beneficial technology. We have never required a unit to undergo NSR before terminating operation; consequently, there is no need for a PCP Exclusion. Commenters raised other scenarios but provided few examples and insufficient detail from which we could draw any conclusions. We believe that the PCP Exclusion will benefit only a subset of all PCPs undertaken at existing sources, in part because most control projects will not cause an emissions increase of any criteria pollutant and, thus, will not trigger NSR. As always, major NSR only applies to your physical or operational changes that result in a significant net emissions increase at your source.

b. What is Meant by ''Environmentally Beneficial''?

The WEPCO PCP Exclusion defines a PCP as ''any activity or project undertaken . . . for purposes of reducing emissions.'' § 52.21(b)(32). We have explained that ''EPA expects that most, if not all, pollution control projects will reduce net actual emissions.'' 57 FR 32319 (1992). The WEPCO PCP Exclusion therefore ''avoids the need to undertake a quantitative emissions increase calculation in every case'' that a facility prepares to undertake a PCP. Rather, in recognition that while a PCP ''could theoretically cause a small collateral increase in some emissions, it will substantially reduce emissions of other pollutants,'' the rule contemplates that sources proposing PCPs that are not listed will determine in the first instance whether they are entitled to the PCP Exclusion based on the ''project's net emissions and overall impact on the environment.'' *Id.* at 32321. Nevertheless, ''the reviewing authority can require additional modeling under certain circumstances to evaluate the air quality impact of a [PCP].'' *Id.*

As for the WEPCO PCP Exclusion, ''reducing emissions'' is the bedrock of the PCP Exclusion. For the list of PCPs in today's regulation, we are satisfied that the net impact on the environment from these projects is beneficial because of our broad experience with these technologies. Consequently, such projects are desirable from an environmental protection perspective, and we have no reason to doubt the validity of the ''environmentally beneficial'' presumption when such controls are applied to existing sources consistent with standard and reasonable practices.

For those projects not listed in Table 2, there is no presumption as to whether or not the projects are environmentally beneficial, and therefore the PCP Exclusion is not self-executing. On a case-by-case basis, your reviewing authority must consider the net environmental benefit of a non-listed project and approve requests for the PCP Exclusion for a specific application of the project upon a showing that it is environmentally beneficial. You must receive this approval from your reviewing authority before beginning actual construction of the PCP. This approval must be conducted through a SIP-approved permitting process that conforms to the requirements of §§ 51.160 and 51.161, including a requirement for a public hearing and 30-day public comment period on all aspects of the project. This includes an opportunity for the public and EPA to review and comment on the environmental benefits analysis and the air quality impacts assessment. The reviewing authority's evaluation of the project's net environmental benefits is limited to air quality considerations; specifically, the air quality benefits of emissions reductions of the primary pollutant must outweigh any detrimental effects from emissions increases in the collateral pollutant, when comparing the unit's post-change emissions to its pre-change baseline actual emissions. Also, the reviewing authority's decision on a case-specific approval of a PCP Exclusion does not serve to proclaim that a given technology is environmentally beneficial for purposes of subsequent PCP Exclusion applications for the same technology.

We may add non-listed control devices, work practices, and pollution prevention projects to the approved list, such that a previously non-listed project can be considered for a self-executing PCP Exclusion. The technology must be reviewed by us to ensure that the project's overall net impact on the environment is indeed beneficial. Our evaluation would hinge on the same factors mentioned above for the reviewing authority's case-by-case reviews. Once ''listed,'' a subsequent project could be presumed environmentally beneficial unless case-specific factors or impacts would indicate otherwise.

Today's rule also provides more guidance in this rule on what constitutes an environmentally beneficial fuel switch. In general, we lack sufficient information from which to categorically determine that a switch to solid fuel will be ''inherently less polluting.'' For instance, switching from oil to woodwaste may decrease sulfur emissions while increasing particulate emissions. Switching between solid fuels, such as coal, woodwaste, or tire-derived fuels, must therefore be evaluated more closely before we can determine whether such a switch could qualify as an environmentally beneficial PCP. Accordingly, we specify which fuel switches are presumptively available for the PCP Exclusion.

c. Why are not More Pollution Prevention Projects Presumed Environmentally Beneficial?

Switching to a less polluting fuel or to a less potent quantity of ODS are prime examples of pollution prevention projects, and both are already listed as presumptively environmentally beneficial. However, some commenters point out that there are far more end-of-pipe, add-on technologies that are listed as environmentally beneficial and recommend that we include more pollution prevention technologies. Although we fully support and encourage pollution prevention projects and strategies, special care must be taken in evaluating a pollution prevention project for the PCP Exclusion. Pollution prevention projects tend to be dependent on site-specific factors and lack an historical record of performance, which proves problematic in deciding whether they are environmentally beneficial when applied universally. We believe that both add-on control devices and pollution prevention projects have equal chances of being presumed environmentally beneficial, but we have more data and history with the add-on control equipment, and this is why the list includes more of those types of pollution strategies. Pollution prevention projects can still qualify as environmentally beneficial PCPs, but they must be evaluated by the reviewing authority to confirm their environmental benefits.

d. How are Control Technologies and Pollution Prevention Strategies Added to the Presumptively ''Environmentally Beneficial'' List?

The proposal would have allowed the reviewing authority to add to the list of presumptively environmentally beneficial technologies, as long as it determined that a project had been ''demonstrated in practice'' and was comparable in effectiveness to the listed technologies on a pollutant-specific basis. We will continue to allow new control technologies that are demonstrated in practice to be added to the list of presumed environmentally beneficial technologies. However, unlike the proposed PCP Exclusion, we will not require that non-listed technologies be comparable in effectiveness on a pollutant-specific basis with the emissions reduction efficiency of currently listed technologies in order to qualify as environmentally beneficial, since this is difficult to compare when different pollutants must be considered. Also, today's rule vests the EPA Administrator with the sole authority to approve non-listed pollution strategies as presumptively environmentally beneficial. The reviewing authority may perform a case-specific approval of a PCP Exclusion in which it would determine that a non-listed technology is environmentally beneficial, but that determination only pertains to the particular case under evaluation and would not serve to presume that the technology is environmentally beneficial for subsequent applications.

Through notice and comment rulemaking, we will maintain and update the list as we deem additional technologies to be environmentally beneficial or to remove from the list any PCP that we erroneously listed.

Several commenters on the proposal suggest that we create a clearinghouse for newly added environmentally beneficial PCPs. We agree that additions to the approved PCP list need to be readily available to the public; however, since rulemaking will be used to add new PCPs to the approved list, no additional public notice will be necessary.

e. How do I Calculate Emissions Increases?

In order to calculate emissions increases for primary and collateral pollutants for the purpose of determining the environmental impact of the PCP, you must use the actual-to-projected-actual applicability test method for calculating the emissions increase. This test is discussed in section II of today's preamble, and is consistent with the remainder of today's rule revisions.

f. How do you Perform the Emissions Calculation for Switches to a Less Potent Amount of ODS?

We have determined that activities or projects undertaken to accommodate switching to an ODS with less potential for stratospheric ozone damage are presumptively environmentally beneficial, as long as the productive capacity of the equipment does not increase as a result of the activity or project.

For determining your emissions before and after the change, you must perform a weighted comparison of the switch based on ozone depleting potential (ODP), taken from 40 CFR part 82, and the past and projected future usage of each ODS. In cases where we have expressed a chemical's ODP in 40 CFR part 82 as a range, the most conservative value (that is, the upper bound value) should be used. The replaced ODP-weighted amount is then calculated by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS. The projected ODP-weighted amount is computed by multiplying the projected future annual usage of the new substance by its ODP. The following example illustrates how to make these calculations in determining whether a switch to a different ODS is environmentally beneficial.

Example: Source plans to replace solvents in its batch process line. Its current solvent, CFC–12, a chlorofluorocarbon (CFC) with an ODP of 1.0, is emitted at 200 tpy. It will be substituted with a less potent solvent, a hydrochlorofluorocarbon (HCFC) with an ODP of 0.02. As a result of this change, the straight mass emissions coming from the solvent will increase twofold due to the new process solvent having a higher vapor pressure than the old solvent. However, this substitution most likely would be viewed as environmentally beneficial, since the ODP-weighted emissions would reveal a decreased risk in environmental harm. Specifically, the CFC–12 would be multiplied by its ODP of 1.0, resulting in 200 tpy for pre-change ODP-weighted emissions. In contrast, the 400 tpy of HCFC emissions would be multiplied by 0.02, giving it a post-change, ODP-weighted emission level of 8 tpy. The net effect is an emissions decrease of 192 tpy on an ODP-weighted basis.

g. Should Cross-Media Impacts be Considered in the ''Environmentally Beneficial'' Demonstration?

By definition, a PCP reduces emissions of air pollutants subject to regulation under the Act. Therefore, while the primary environmental benefit of the PCP would be to reduce air emissions, a secondary benefit could be reducing pollution in other media. However, these cross-media tradeoffs are difficult to compare, so it is difficult to weigh their importance in appraising the overall environmental benefit of a PCP. We solicited comments in the proposal on how to compare cross-media pollution, but we received no suggestions on how to design such a system. As a result, we have determined that it is inappropriate to consider non-air impacts when considering whether projects, activities, or work practices qualify for the PCP Exclusion.

3. Air Quality Impacts

a. What is the ''Cause-or-Contribute Test''?

Another criterion for qualification for all PCPs is that the emissions from the PCP cannot cause or contribute to a violation of any NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM, and for which information is available to the general public. This has been called the ''cause-or-contribute test.'' We continue to believe that the PCP Exclusion must include such safeguards to ensure protection of the environment and public health. In the WEPCO PCP Exclusion, we said that the reviewing authority ''under certain circumstances'' may evaluate the air quality impact of a PCP. 57 FR 32321. Generally, these circumstances would include large secondary emissions increases in areas that are nonattainment, or marginally in attainment, for the pollutant in question. We anticipate, however, that such analyses would not normally be required, since collateral emissions increases from most relevant projects will be so small that additional modeling should not be required.

Commenters from industry complain that determining whether there would be an adverse impact on an AQRV is too difficult and believe that the proposal is ambiguous in defining roles of FLMs and reviewing authorities. The intention of the statutory structure for preconstruction permit review in section 165(d) of the Act unambiguously is to protect against any adverse impact on AQRVs in Class I lands. Therefore, we continue to believe that any air quality assessment for a PCP should consider all relevant AQRVs in any Class I area that are identified by the FLM at the time you submit your notice or permit application for the project. For purposes of those projects on the list of projects presumptively qualifying for the PCP Exclusion, we are limiting the consideration of AQRVs to those that have already been identified by an FLM for the Federal Class I area. You should check with the National Park Service website and other public information to determine if the FLM has already identified an AQRV for a nearby Class I area. If you are required to obtain both approval from your reviewing authority and a permit before beginning actual construction of your project, then additional AQRVs may be identified by an FLM consistent with the procedures provided for in that permitting process.

b. What is Necessary for the Air Quality Impacts Analysis?

Reviewing authorities can require you to analyze your air quality impacts whenever they have reason to believe that: (1) the project will result in a significant emissions increase of any criteria pollutant over levels in the most recent analysis; and (2) such an increase would cause or contribute to a violation of any NAAQS or PSD increment or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. The analysis must contain sufficient data to satisfy the reviewing authority that the new levels of emissions will not cause or contribute to a violation of the NAAQS or PSD increment, or adversely impact an AQRV (such as visibility) that has been identified for a Federal Class I area by an FLM and for which information is available to the general public. If the air quality analysis shows that a resulting violation is foreseeable, your project cannot receive the PCP Exclusion.

Many industry commenters complain that the proposed air quality analysis and Class I provisions for the exclusion were overly burdensome and needed to be either eliminated or streamlined. We agree in part with this point, even though we strongly contend that there need to be safeguards to protect against misuse of the exclusion with projects that will not provide positive environmental results. Although today's final rule contains the core safeguard to prevent an adverse air quality impact, a modeling exercise is not necessarily warranted in all cases.

While you are not required to notify the FLM of any Federal Class I area located near your facility as a prerequisite for proceeding with a PCP, you must determine whether any AQRVs have been identified in these areas. FLMs have identified AQRVs for many of the Federal Class I areas and made this information available on a dedicated web site (*http://www2.nature.nps.gov*). If no AQRVs have been identified for a particular Class I area, your demonstration is simply a statement that no AQRVs exist in Class I areas that your source has the potential to affect. Similarly, if there are AQRVs in nearby Federal Class I areas, but the pollutants associated with these AQRVS either will not be emitted by your facility or will not increase by a significant amount as a result of the PCP, then your demonstration should simply indicate the lack of any association between your PCP project and the known AQRVs.

On the other hand, you should be prepared to conduct modeling with respect to any regulated NSR pollutant that your PCP will cause to increase by a significant amount when that pollutant is associated with a known AQRV in a nearby Federal Class I area. Oftentimes, a screening model may be used to estimate the ambient impacts of the increase from your facility. Special concern should be given in cases where an FLM has already identified adverse impacts for such AQRV. In such cases, you are expected to record and consider any information that the FLM has made available concerning the adverse effects, to help determine whether the pollutant impacts from your facility have the potential to cause further adverse impacts.

If a reviewing authority, upon receiving your notification of using the PCP Exclusion, believes that an air quality impacts analysis is reasonably necessary, it is entitled to request more information from you, including additional local or regional modeling.

c. How does the PCP Exclusion Apply to Projects With Collateral Pollutant Increases of Nonattainment Pollutants?

The PCP Exclusion is available, regardless of an area's attainment status or its severity of nonattainment. Nonetheless, because increases in a nonattainment pollutant contribute to the existing nonattainment problem, you or the reviewing authority must offset with acceptable emissions reductions any significant emissions increase in a nonattainment pollutant resulting from a PCP. We are promulgating the PCP Exclusion consistent with our proposal's approach of requiring mitigation of any significant emissions increase of a nonattainment pollutant resulting from a PCP.

Since less than significant collateral emissions increases (for example, less than 40 tpy of VOC in a moderate ozone nonattainment area) do not trigger major NSR, such mitigation requirements are not necessary for the PCP Exclusion when the increase of the nonattainment pollutant will be below the applicable significant level. Be aware, however, that a less than significant emissions increase may be subject to a State's minor NSR requirements.

4. Miscellaneous

a. Can you Generate ERCs From Your PCP-Excluded Project?

The proposal would have allowed certain projects approved for the PCP Exclusion to use their primary pollutant(s) emissions reductions as NSR offsets or netting credits. We included in the proposed rule a specialized ''environmentally beneficial'' test that would apply to PCPs that generate ERCs. Some commenters support allowing ERCs and creating more flexibility to use them. However, other commenters recommend that EPA avoid complicating the PCP Exclusion by factoring emissions trading credits with the exclusion. These commenters claim that the parceling out of the appropriate reductions for emissions credits and for the newly installed PCP would take an enormous amount of time, and cause problems with tracking emissions reductions and using the credits.

We no longer believe it would be prudent to allow PCPs to generate netting credits or offsets for the emissions reductions used to initially qualify the project for the PCP Exclusion, in light of the issues of increased complexity that the commenters raise. But perhaps more importantly, we feel that the emissions reductions initially achieved by the PCP are integral to the ''environmentally beneficial'' demonstration required in order for the PCP to qualify for the exclusion. The emissions reductions are traded, in effect, for the significant emissions increase of the collateral pollutants and for the benefits of being excluded from the major NSR permitting requirements. To then re-use the reductions would weaken the PCP Exclusion and would not ensure appropriate environmental protection. Consequently, you cannot use emissions reductions that initially qualified a project for the PCP Exclusion as netting credits or offsets.

However, you are allowed to continue to use these reductions to generate allowances for purposes of complying with the title IV Acid Rain program. In

1992, the PCP Exclusion was originally designed for use by EUSGUs because we did not envision that Congress intended for the NSR program to apply to projects undertaken to comply with title IV. Nothing in today's proposal is intended to change that design.

Moreover, once you qualify for the PCP Exclusion, you can apply for ERCs if you change your process conditions in such a way that further reduces emissions. For example, consider that you have an add-on control technology which receives a PCP Exclusion that, at full operation, allows the source to increase its emissions of a specific collateral pollutant and emit 100 tpy of a pollutant (either a targeted pollutant or a collateral pollutant). If you later decide to take an hours-of-operation limit for your process line and/or control technology that reduces your emissions of that pollutant to 75 tpy, then this 25 tpy reduction in emissions can be used as ERCs if deemed acceptable in all other respects by your reviewing authority.

b. Why Are We Deleting the ''Primary Purpose'' test?

The ''primary purpose'' test was proposed as an initial screening mechanism for reviewing authorities to screen out inappropriate projects and to streamline the approval process. This was designed to help reviewing authorities avoid dedicating unnecessary resources to non-qualifying projects. Furthermore, we recognized that all of the listed PCPs have a primary purpose of reducing air pollution, so it followed logically that any other PCP should have the same primary purpose.

However, we received comments from both industry and a State trade association stating that many activities and projects have multiple purposes in addition to reducing emissions, and they encourage EPA not to focus on the primary purpose of a project, but rather on the project's net environmental benefit, in considering it for a PCP Exclusion. A ''primary purpose'' requirement would disqualify projects that may be environmentally beneficial but happen to not have pollution control as their primary purpose. Further, one commenter stated that by focusing on the intent of the project rather than its end result, administrative agencies will unnecessarily be forced to devote scarce resources to making these determinations.

We concur with these comments and have determined that this test is potentially unnecessarily restrictive. Our primary objective in allowing for a PCP Exclusion is to offer NSR relief for those projects that create a net environmental benefit, and thus we should not concern ourselves with a source's motivation for undertaking its project. Therefore, by today's rule revisions, even if a project's primary purpose is not to reduce emissions, it can still qualify for the PCP Exclusion if it meets the ''environmentally beneficial'' and air quality tests set forth in today's regulations.

c. How Do the Listed PCP Technologies Compare to BACT or LAER Determinations?

The list of presumed environmentally beneficial technologies contains several control strategies that do not qualify as BACT or LAER. For example, installing low-NO_X burners on large-sized turbines would rarely constitute an acceptable BACT level. However, these projects are presumed environmentally beneficial and are eligible for the PCP Exclusion from major NSR because these controls are cleaner than the existing equipment is without the controls. In addition, the PCP Exclusion only applies to sources that are installing PCPs, and not to the installation of new emissions units or changes that increase the capacity of the unit, both of which would be potentially subject to BACT or LAER. We reiterate, however, that merely because a control technology is listed as environmentally beneficial does not also imply that the technology is equivalent to BACT or LAER, and you should not rely on any such implication as a presumptive BACT or LAER determination.

d. Is the Intent of the PCP Exclusion to Allow Collateral Pollutant Emissions to go Uncontrolled?

To qualify for the PCP Exclusion, you must minimize emissions of collateral pollutants within the physical configuration and operational standards usually associated with the emissions control device or strategy. This typically occurs by inherent design of the control device that causes them. In most cases, no additional control requirements will be necessary.

e. What Does ''Demonstrated in Practice'' Mean?

Representatives from industry comment that we should ease restrictions that require new add-on technologies to be demonstrated in practice. We are continuing to require that new technologies be demonstrated in practice before being added to the list, in part because this is an important element in a showing that the candidate technology is environmentally sound. However, we have expanded the meaning of ''demonstrated in practice'' to include technologies demonstrated outside of the United States.

f. How Can the Public Participate in the PCP Exclusion Decision for Your Project?

By these rule revisions, we are not requiring any review of your PCP by the public or your reviewing authority prior to enabling the use of the exclusion. Nonetheless, existing State regulations for minor NSR will continue to apply to projects that qualify for the PCP Exclusion and are not otherwise excluded under the State program. Minor NSR programs are designed to consider the impact these increases could have on air quality, including whether local conditions justify rebutting the presumption that a listed project is environmentally beneficial. Nothing in this rule voids or otherwise creates an exclusion from any otherwise applicable minor NSR preconstruction review requirement in any SIP that has been approved pursuant to section 110(a)(2)(C) of the Act and 40 CFR 51.160 through 51.164. The minor NSR permits may afford the public an opportunity to review and comment on the use of the PCP Exclusion for a specific project. *See* §§ 51.160 and 51.161. Furthermore, to undertake a PCP Exclusion, you could use the title V permit revision process to officially effect the PCP Exclusion. This would enable the public to review the PCP determination at that time.

Thus, the process for implementing a PCP Exclusion would be similar to the other exemptions within NSR (routine maintenance, change in ownership, etc.) whereby you are empowered to make the proper decision based on the facts of the case and the rule requirements.

C. Legal Basis for PCP

In 1992, we revised the NSR regulations to exclude PCPs at existing EUSGUs. *See* 57 FR 32314 (July 21, 1992), amending §§ 51.165(a)(1)(v)(C)(8), 51.166(b)(2)(iii)(h), and 52.21(b)(2)(iii)(h). There, we stated that we believed ''that Congress did not intend that PCPs be considered the type of activity that should trigger NSR.'' 57 FR 32319. Although the 1992 rulemaking applied only to EUSGUs, we believe that Congress's intention holds true for other industry sectors as well. Congress could not have intended to require that, and the Act should not be construed such that, physical or operational changes undertaken to reduce emissions undergo NSR. Therefore, in today's action, we are revising the PCP Exclusion and removing the conditions limiting it to EUSGUs.

In the event that a PCP results in a significant emissions increase of a different pollutant, the reviewing authority may require an analysis of air quality impacts which would serve the same function as an air quality impacts analysis conducted as part of NSR permitting. Providing an exclusion for PCPs enables facilities to reduce emissions without having to wait for a major NSR permit to be issued. We believe that this result is consistent with the objectives of the NSR provisions in the CAA. Thus, we are revising our rules to remove disincentives to pollution control and pollution prevention projects to the extent allowed under the CAA.

D. Implementation

1. How Do You Apply For and Receive a PCP Exclusion?

The process for obtaining a PCP Exclusion basically breaks down into two separate scenarios, depending on whether your proposed project is ''listed'' or ''non-listed'' as environmentally beneficial. Both processes are presented below.

a. What Is the Process You Must Follow for Projects Involving Listed PCPs?

Before you begin actual construction on your PCP, you must submit a notice to your reviewing authority that includes the following information (and depending on your reviewing authority's requirements, this information may be submitted with a part 70, part 71 or other SIP-approved permit application such as a minor NSR permit application): (1) A description of project; (2) an analysis of the environmentally beneficial nature of the PCP, including a projection of emissions increases and decreases (speciated, using an appropriate emissions test for the emissions unit); and (3) a demonstration that the project will not have an adverse air quality impact.

You may begin construction on the PCP immediately upon submitting your notice to the reviewing authority. However, if your reviewing authority determines that the source does not qualify for a PCP Exclusion, you may be subject to a delay in the project or an order to not undertake the project.

b. What Is the Process You Must Follow for Projects Involving Non-Listed PCPs?

For projects not listed in Table 2, on a case-by-case basis your reviewing authority must consider the net environmental benefit of a non-listed project and, within a reasonable amount of time, act upon your request for the exclusion for a specific application. You must receive this approval from your reviewing authority before beginning actual construction of the PCP. Your reviewing authority will provide an opportunity for public review and comment prior to granting its approval for the PCP.

Your application for case-specific approval of a PCP Exclusion should have the same information as required above for a notice to use a listed technology. The only difference between the two processes is that the use of a listed technology allows you to commence construction on your PCP immediately after submitting your notice to the reviewing authority, whereas the use of a non-listed technology requires you to first submit an application to your reviewing authority and obtain its approval prior to construction of your PCP.

2. What Process Will We Follow To Add New Projects to the List of Environmentally Beneficial PCPs?

We will use notice and comment rulemaking procedures to add new projects to the list of PCPs that are presumed to be environmentally beneficial. We may take this action on our own initiative or you may petition us, if you believe there is a project that should be added to the list.

If you submit a petition to us requesting that a non-listed air pollution control technology (which includes pollution prevention or work practices) be determined environmentally beneficial and presumptively qualified for the PCP Exclusion, you should describe the anticipated emissions consequence of installing the PCP, both for primary and collateral pollutants. We will review your submittal within a reasonable amount of time. If we believe that the project should be added to the list, we will amend the list of approved PCPs through rulemaking. Once the rule has been amended, you may use a newly listed PCP if you proceed in accordance with the process for implementing the PCP Exclusion for listed PCPs. (*See* section VI.D.1.a.)

3. What Are Our Operational Expectations for an Excluded PCP?

By this rule, we are creating a general duty for all sources approved to use a PCP Exclusion. This general duty clause requires you to operate the PCP in a manner consistent with reasonable engineering practices and with the basic applicability requirements for the exclusion (*i.e.*, being environmentally beneficial and having no adverse air quality impacts). This means that you have a legal responsibility to operate in a manner that is consistent with your analysis of the environmental benefits and air quality impacts analysis, and that you will minimize collateral pollutant increases within the physical configuration and operational standards usually associated with the emissions control device or strategy.

4. What Are the Implications of Not Complying With the PCP Exclusion Process?

The PCP Exclusion is a mechanism for bypassing the major NSR permitting requirements. If you do not comply with the steps necessary to qualify for the PCP Exclusion under the terms of the PCP provisions, you can become subject to major NSR.

VII. Listed Hazardous Air Pollutants

The 1990 Amendments to the CAA at section 112(b)(6) exempted HAP listed under section 112(b)(1) from the PSD requirements in part C. In our 1996 **Federal Register** Notice, we proposed changes to the regulations at §§ 51.166 and 52.21 to implement this exemption. Specifically, we proposed the following.

• The HAP listed in section 112(b)(1), as well as any pollutant that may be added to the list, are excluded from the PSD provisions of part C. These HAP include arsenic, asbestos, benzene, beryllium, mercury, radionuclides, and vinyl chloride, all of which were previously regulated under the PSD rules. This exemption applies to the provisions for major stationary sources in §§ 51.166(b)(2) and 52.21(b)(2), the significant levels in §§ 51.166(b)(23)(i) and 52.21(b)(23)(i), and the significant monitoring concentrations in §§ 51.166(i)(8) and 52.21(i)(8).

• Pollutants listed in regulations pursuant to section 112(r)(1), Accidental Release, are not excluded from the PSD provisions of part C.

• Any HAP listed in section 112(b)(1) that are regulated as constituents or precursors of a more general pollutant listed under section 108 are still subject to PSD, despite the exemption in section 112(b)(6).

• If a pollutant is removed from the list under the provisions of section 112(b)(3) of the Act, that pollutant would be subject to the applicable PSD requirements of part C if it is otherwise regulated under the Act.

• Pollutants regulated under the Act and not on the list of HAP, such as fluorides, TRS compounds, and sulfuric acid mist, continue to be regulated under PSD.

Public commenters generally agree that our proposal reflects the statutory requirements. Therefore, today we are taking final action to promulgate these proposed provisions at §§ 51.166(b)(23)(i), 51.166(i)(8), 52.21(b)(23)(i), and 52.21(i)(8).

As today's regulations provide, the following pollutants currently regulated under the Act are subject to Federal PSD review and permitting requirements.

- CO
- NO_X
- SO_2
- PM and particulate matter less than 10 microns in diameter (PM–10)
- Ozone (VOC)
- Lead (Pb) (elemental)
- Fluorides (excluding hydrogen fluoride)
- Sulfuric acid mist
- H_2S
- TRS compounds (including H_2S)
- CFCs 11, 12, 112, 114, 115
- Halons 1211, 1301, 2402
- Municipal Waste Combustor (MWC) acid gases, MWC metals, and MWC organics
- ODS regulated under title VI

The PSD program applies automatically to newly regulated NSR pollutants, which would include final promulgation of an NSPS applicable to a previously unregulated pollutant.

As we indicated in our proposal package, CAA section 112(b)(7) states that elemental Pb (the named chemical) may not be listed by the Administrator as a HAP under section 112(b)(1). Therefore, because section 112(b)(6) exempts only the pollutants listed in section 112, elemental Pb emissions are not exempt from the Federal PSD requirements. Elemental Pb continues to be a criteria pollutant subject to the Pb NAAQS and other requirements of the Act. As proposed, we are also continuing to maintain that the reference to Pb in the regulations regarding the significant levels and significant monitoring concentrations covers the Pb portion of Pb compounds. *See* §§ 51.166(b)(23), 51.166(i)(8), 52.21(b)(23), and 52.21(i)(8). Otherwise, the word elemental might imply that only Pb that is not part of a Pb compound is covered.

One commenter requests that we amend the regulations to include a definition of pollutants regulated under the Act. We agree with the commenter that such a provision would clarify which pollutants are covered under the PSD program. Moreover, the nonattainment NSR rules at § 51.165 would also benefit from this clarity. Therefore, today's final regulations include a definition for regulated NSR pollutant. This new definition replaces the terminology ''pollutants regulated under the Act.''

The term ''Regulated NSR pollutant'' includes the following pollutants.

- NO_X or any VOC
- Any pollutant for which a NAAQS has been promulgated
- Any pollutant that is subject to any standard promulgated under section 111 of the Act
- Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act.

The new definition excludes HAPs listed in section 112 of the Act (including any pollutants that may be added to the list pursuant to section 112(b)(2) of the Act). However, when any pollutant listed under section 112 of the Act is also a constituent or precursor of a more general pollutant that is regulated under section 108 of the Act, that listed pollutant may be regulated under NSR but only as part of regulation of the general pollutant.

As we indicated in our proposal, State and local agencies with an approved PSD program may continue to regulate the HAP now exempted from Federal PSD by section 112(b)(6) if their PSD regulations provide an independent basis to do so. These State and local rules remain in effect unless they are revised to provide similar exemptions. Such provisions that are part of the SIP are federally enforceable.

Section 112(q) retains existing NESHAP regulations by specifying that any standard under section 112 in effect before the enactment of the 1990 Amendments remains in force. Therefore, the requirements of §§ 61.05 to 61.08, including preconstruction permitting requirements for new and modified sources subject to existing NESHAP regulations, are still applicable.

Pollutants listed under section 112(r) are not included in the definition of regulated NSR pollutant. As we proposed, substances regulated under section 112(r) may still be subject to PSD if they are regulated under other provisions of the Act. For example, even though H_2S is listed under section 112(r), it is still regulated under the Federal PSD provisions because it is regulated under the NSPS program in section 111. This means that the listing of a substance under section 112(r) does not exclude the substance from the Federal PSD provisions; the PSD provisions apply if the substance is otherwise regulated under the Act.

We are not taking final action on ambient impact concentrations or maximum allowable increases in pollutant concentrations as proposed in § 51.166(b)(23)(iv) and (v) and § 52.21(b)(23)(iv) and (v). Although these provisions are included in the definition of significant, they do not relate to the new provisions for HAP. Instead, they concern Class I issues, which we have not taken final action on.

VIII. Effective Date for Today's Requirements

As discussed above, today we are changing the existing NSR requirements in five ways.

- Providing a new method for determining baseline actual emissions
- Adopting the actual-to-projected-actual methodology for determining whether a major modification has occurred
- Allowing major stationary sources to comply with PALs to avoid having a significant emissions increase that triggers the requirements of the major NSR program
- Providing new applicability provisions for emissions units that are designated Clean Units
- Excluding PCPs from the definition of ''physical change or change in the method of operation''

Today's rules codify our longstanding policy for calculating the baseline actual emissions for EUSGUs, which is any consecutive 2 years in the past 5 years, or another more representative period. In today's final rules we are also including a new section that outlines how a major modification is determined under the various major NSR applicability options and clarifies where you will find the provisions in our revised rules.

All of these changes will take effect in the Federal PSD program (codified at § 52.21) on March 3, 2003. This means that these rules will apply on March 3, 2003, in any area without an approved PSD program, for which we are the reviewing authority, or for which we have delegated our authority to issue permits to a State or local reviewing authority.

To be approvable under the SIP, State and local agency programs implementing part C (PSD permit program in § 51.166) or part D (nonattainment NSR permit program in § 51.165) must include today's changes as minimum program elements. State and local agencies should assure that any program changes under §§ 51.165 and 51.166 are consistently accounted for in other SIP planning measures. State and local agencies must adopt and submit revisions to their part 51 permitting programs implementing these minimum program elements no later than January 2, 2006. That is, for both nonattainment and attainment areas, the SIP revisions must be adopted and submitted within 3 years from today. The Act does not specify a date for submission of SIPs when we revise the PSD and NSR rules. We believe it is appropriate to establish a date analogous to the date for submission of new SIPs when a NAAQS is promulgated or revised. Under section 110(a)(1) of the Act, as amended in 1990, that date is 3 years from promulgation or revision of the NAAQS. Accordingly, we have established 3 years from today's revisions as the required date for submission of conforming SIP revisions. We have made conforming changes to the PSD regulations at § 51.166(a)(6)(i) to indicate that State and local agencies must adopt and submit plan revisions within 3 years after new amendments are published in the **Federal Register**.

In our 1996 proposed rule, we solicited comment on a new approach for implementing the applicability-related NSR improvements (*i.e.*, PALs, the Clean Unit provision, the PCP Exclusion, and provisions related to measuring emissions increases). We noted that the Agency in the past ''has essentially required States to follow a single applicability methodology,'' but that ''States could, of course, have a more stringent approach.'' 61 FR 38253. Instead of following this normal course, we proposed to establish the new applicability provisions as a ''menu'' of options. Under this approach, we would have allowed States to adopt into their NSR programs all, some, or none of the new provisions.

In today's final rule, we have decided not to implement the menu approach. We have opted instead to retain our longstanding approach of incorporating all of the new provisions into our ''base'' NSR program requirements, which are set forth in §§ 51.165, 51.166, and 52.24. The same provisions will be included in § 52.21, our own PSD permitting program. Our decision is based primarily on our belief that the NSR program will work better as a practical matter and will produce better environmental results if all five of the new applicability provisions are adopted and implemented. We and our stakeholders invested unprecedented amounts of time, energy, and resources in deciding how best to improve the NSR program. After well over a decade of sustained effort, we believe that we have found effective solutions to many of the program's most intractable problems. We hope that making the new provisions part of our base programs will provide incentive for these provisions to be adopted on a widespread basis.

Notably, even without the menu approach, State and local jurisdictions have significant freedom to customize their NSR programs. Ever since our current NSR regulations were adopted in 1980, we have taken the position that States may meet the requirements of part 51 ''with different but equivalent regulations.'' 45 FR 52676. Several States have, indeed, implemented programs that work every bit as well as our own base programs, yet depart substantially from the basic framework established in our rules. A good example is Oregon, where the SIP-approved program requires all major sources to obtain plantwide permits not unlike the PALs that we are finalizing today. Oregon's program plainly illustrates that we have not implemented our base programs with a one-size-fits-all mentality and certainly do not have the goal of ''preempting'' State creativity or innovation.

Perhaps the biggest potential disadvantages to implementing the new applicability provisions as part of our base programs are the time and effort required to revise existing State programs and to have the revised programs approved as part of the SIP. For States that choose to adopt all of the new applicability provisions, we expect that the SIP approval process will be expeditious. Of course, the review and approval process will be more complicated for States that choose to adopt a program that differs from our base programs. For example, if a State decides it does not want to implement any of the new applicability provisions, that State will need to show that its existing program is at least as stringent as our revised base program. It would be impossible for us to plan ahead for all of the possible variations that States might ultimately elect to pursue. We will, however, reach out to relevant stakeholders immediately after publication of these rules and try to develop streamlined methods for addressing common questions that may arise during the SIP approval process.

IX. Administrative Requirements

A. Executive Order 12866—Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is ''significant'' and therefore subject to OMB review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has notified us that it considers this rule a ''significant regulatory action.'' As such, this action was submitted to OMB for review.

B. Executive Order 13132—Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. While this final rule will result in some expenditures by the States, we expect those expenditures to be limited to $331,250 per year. This figure includes the small increase in the burden imposed upon reviewing authorities in order for them to revise the State's SIP. However, these revisions provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. Thus, Executive Order 13132 does not apply to this rule. Nevertheless, in the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, we specifically solicited comment on the proposed rule from State and local officials.

C. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' We believe that this final rule does not have tribal implications as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this rule.

EPA began considering potential revisions to the NSR rules in the early 1990's and proposed changes in 1996. The purpose of today's final rule is to add greater flexibility to the existing major NSR regulations. These changes will benefit both reviewing authorities and the regulated community by providing increased certainty as to when the requirements apply, and by providing alternative ways to comply with the requirements. Taken as a whole, today's final rule should result in no added burden or compliance costs and should not substantially change the level of environmental performance achieved under the previous rules.

We anticipate that initially these changes will result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, as well as other small increases in burden discussed under ''Paperwork Reduction Act.'' Nevertheless, these revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In comparison, no tribal government currently has an approved tribal implementation plan (TIP) under the CAA to implement the NSR program. The Federal government is currently the NSR reviewing authority in Indian country, thus tribal governments should not experience added burden, nor should their laws be affected with respect to implementation of this rule. Additionally, although major stationary sources affected by today's final rule could be located in or near Indian country and/or be owned or operated by tribal governments, such sources would not incur additional costs or compliance burdens as a result of this rule. Instead, the only effect on such sources should be the benefit of the added certainty and flexibility provided by the rule.

We recognize the importance of including tribal consultation as part of the rulemaking process. Although we did not include specific consultation with tribal officials as part of our outreach process on this final rule, which was developed largely prior to issuance of Executive Order 13175 and which does not have tribal implications under Executive Order 13175, we will continue to consult with tribes on future rulemakings to assess and address tribal implications, and will work with tribes interested in seeking TIP approval to implement the NSR program to ensure consistency of tribal plans with this rule.

D. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children because we believe that this package as a whole will result in equal or better environmental protection than currently provided by the existing regulations, and do so in a more streamlined and effective manner.

E. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost effective or least burdensome alternative if the Administrator publishes with the final rule an explanation as to why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan.

The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Although initially these changes are expected to result in a small increase in the burden imposed upon reviewing authorities in order for them to be included in the State's SIP, as well as other small increases in burden discussed under ''Paperwork Reduction Act,'' these revisions will ultimately provide greater operational flexibility to sources permitted by the States, which will in turn reduce the overall burden of the program on State and local authorities by reducing the number of required permit modifications. In addition, we believe the rule changes will actually reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Thus, today's rule is not subject to the requirements of sections 202 and 205 of the UMRA.

For the same reasons stated above, we have determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. Thus, today's rule is not subject to the requirements of section 203 of the UMRA.

F. Regulatory Flexibility Analysis

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) Any small business employing fewer than 500 employees; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, we have concluded that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may conclude that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect, on all of the small entities subject to the rule.

A Regulatory Flexibility Act Screening Analysis (RFASA), developed as part of a 1994 draft Regulatory Impact Analysis (RIA) and incorporated into the September 1995 ICR renewal analysis, showed that the changes to the NSR program due to the 1990 CAA Amendments would not have an adverse impact on small entities. This analysis encompassed the entire universe of applicable major sources that were likely to also be small businesses (approximately 50 ''small business'' major sources). Because the administrative burden of the NSR program is the primary source of the NSR program's regulatory costs, the analysis estimated a negligible ''cost to sales'' (regulatory cost divided by the business category mean revenue) ratio for this source group. Currently, and as reported in the current ICR, there is no economic basis for a different conclusion.

We believe these rule changes will reduce the regulatory burden associated with the major NSR program for all sources, including all small businesses, by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. As a result, the program changes provided in the final rule are not expected to result in any increases in expenditure by any small entity.

We have therefore concluded that today's final rule will relieve regulatory burden for all small entities.

G. Paperwork Reduction Act

The information collection requirements in this rule will be contained in two different Information Collection Requests (ICRs).

The Office of Management and Budget (OMB) has approved the information collection requirements contained under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0003 (ICR 1230.10). The EPA prepared an ICR document (ICR No. 1230.10) extending the approval of the ICR for the promulgated NSR regulations on March 30, 2001. On October 29, 2001, OMB approved EPA's request for extension for 3 years until October 31, 2004. The OMB number for this approval is 2060–0003.

In addition to the existing ICR, the information collection requirements in this final rule have been submitted for approval to OMB under the requirements of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An ICR document has been prepared by EPA (ICR No. 2074.01), and a copy may be obtained from Susan Auby, U.S. Environmental Protection Agency, Office of Environmental Information, Collection Strategies Division (2822T), 1200 Pennsylvania Avenue, NW., Washington, DC 20460–0001, by e-mail at *auby.susan@epa.gov,* or by calling (202) 566–1672. A copy may also be downloaded off the Internet at *http://www.epa.gov/icr.* The information requirements included in ICR No. 2074.01 are not effective until OMB approves them.

The information that ICR No. 2074.01 covers is required for the submittal of a complete permit application for the construction or modification of all major new stationary sources of pollutants in attainment and nonattainment areas, as well as for applicable minor stationary sources of pollutants. This information collection is necessary for the proper performance of EPA's functions, has practical utility, and is not unnecessarily duplicative of information we otherwise can reasonably access. We have reduced, to the extent practicable and appropriate, the burden on persons providing the information to or for EPA.

According to ICR No. 2074.01, as a result of the rule changes, the total 3-year burden change of the revised collection is estimated at about 219,741 hours at a total cost of $7.7 million. The annual burden change to industry is about 64,287 hours at a cost of $2.2 million. The annual burden change to reviewing agencies is about 8,960 hours at a cost of $331,520. The total annual respondent change is 73,247 hours for a total respondent change in cost of $2.6 million. These costs changes are based upon 62 PSD and 123 NSR non-utility sources (185 total); and 85 PSD and 169 NSR (254 total) sources, including utilities. For the number of respondent reviewing authorities, the analysis uses the 112 reviewing authorities count used by other permitting ICRs for the one-time tasks (for example, SIP revisions) and the appropriate source count for individual permit-related items (for example, attending pre-application meetings with the source). There is only one Federal source listed in the ICR.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purpose of responding to the information collection; adjust existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15. We will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the Agency's regulations, and in each CFR volume containing EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements, and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the *Paperwork Reduction Act* (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

H. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Pub. L. 104–113, 12(d) (15 U.S.C. 272 *note*) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical.

Voluntary consensus standards are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. This final rule does not create new requirements but, rather, revises an existing permitting program by providing a series of program options that affected facilities may choose to adopt. These options will reduce the regulatory burden associated with the major NSR program by improving the operational flexibility of owners and operators, improving the clarity of requirements, and providing alternatives that sources may take advantage of to further improve their operational flexibility. Therefore, EPA did not consider the use of any voluntary consensus standards.

I. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). Nonetheless, the Agency has decided to provide an effective date that is 60 days after publication in the **Federal Register**. This rule will be effective March 3, 2003.

J. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Today's rule improves the ability of sources to undertake pollution prevention or energy efficiency projects, switch to less polluting fuels or raw materials, maintain the reliability of production facilities, and effectively utilize and improve existing capacity. The rule also includes a number of provisions to streamline administrative and permitting processes so that facilities can quickly accommodate changes in supply and demand. The regulations provide several alternatives that are specifically designed to reduce administrative burden for sources that use pollution prevention or energy efficient projects.

X. Statutory Authority

The statutory authority for this action is provided by sections 101, 112, 114, 116, and 301 of the Act as amended (42 U.S.C. 7401, 7412, 7414, 7416, and 7601). This rulemaking is also subject to section 307(d) of the Act (42 U.S.C. 7407(d)).

XI. Judicial Review

Under section 307(b)(1) of the Act, judicial review of this final rule is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by March 3, 2003. Any such judicial review is limited to only those objections that are raised with reasonable specificity in timely comments. Under section 307(b)(2) of the Act, the requirements that are the subject of this final rule may not be challenged later in civil or criminal proceedings brought by us to enforce these requirements.

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practices and procedures, Air pollution control, BACT, Baseline emissions, Carbon monoxide, Clean Units, Hydrocarbons, Intergovernmental relations, LAER, Lead, Major modifications, Nitrogen oxides, Ozone, Particular matter, Plantwide applicability limitations, Pollution control projects, Sulfur oxides.

40 CFR Part 52

Environmental protection, Administrative practices and procedures, Air pollution control, BACT, Baseline emissions, Carbon monoxide, Clean Units, Hydrocarbons, Intergovernmental relations, LAER, Lead, Major modifications, Nitrogen oxides, Ozone, Particulate matter, Plantwide applicability limitations, Pollution control projects, Sulfur oxides.

Dated: November 22, 2002.

Christine Todd Whitman,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51—[Amended]

1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401—7671 q.

Subpart I—[Amended]

2. In 40 CFR 51.165(a)(1)(i), remove the words "any air pollutant subject to regulation under the Act," and add, in their place, the words "a regulated NSR pollutant."

3. In addition to the amendments set forth above, in 40 CFR 51.165 (a)(1)(iv)(A)(*1*), remove the words "pollutant subject to regulation under the Act" and add, in their place, the words "regulated NSR pollutant."

4. In addition to the amendments set forth above, § 51.165 is amended:

a. By revising the introductory text in paragraph (a).

b. By revising paragraphs (a)(1)(v)(A) and (B).

c. By revising paragraph (a)(1)(v)(C)(*8*).

d. By adding paragraph (a)(1)(v)(D).

e. By revising paragraph (a)(1)(vi)(A).

f. By revising paragraph (a)(1)(vi)(C).

g. By revising paragraph (a)(1)(vi)(E)(*2*).

h. By revising paragraph (a)(1)(vi)(E)(*4*).

i. By adding paragraph (a)(1)(vi)(E)(*5*).

j. By adding paragraph (a)(1)(vi)(G).

k. By revising paragraph (a)(1)(vii).

l. By revising paragraph (a)(1)(xii).
m. By revising the introductory text in paragraph (a)(1)(xiii).
n. By revising paragraph (a)(1)(xviii).
o. By reserving paragraph (a)(1)(xxi).
p. By revising paragraph (a)(1)(xxv).
q. By adding paragraphs (a)(1)(xxvi) through (xlii).
r. By revising paragraph (a)(2).
s. By adding paragraphs (a)(3)(ii)(H) through (J).
t. By adding paragraphs (a)(6) through (7).
u. By adding paragraphs (c) through (g).

The revisions and additions read as follows:

§ 51.165 Permit requirements.

(a) State Implementation Plan and Tribal Implementation Plan provisions satisfying sections 172(c)(5) and 173 of the Act shall meet the following conditions:

(1) * * *

(v) * * *

(A) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in:

(*1*) A significant emissions increase of a regulated NSR pollutant (as defined in paragraph (a)(1)(xxxvii) of this section); and

(*2*) A significant net emissions increase of that pollutant from the major stationary source.

(B) Any significant emissions increase (as defined in paragraph (a)(1)(xxvii) of this section) from any emissions units or net emissions increase (as defined in paragraph (a)(1)(vi) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(C) * * *

(*8*) The addition, replacement, or use of a PCP, as defined in paragraph (a)(1)(xxv) of this section, at an existing emissions unit meeting the requirements of paragraph (e) of this section. A replacement control technology must provide more effective emissions control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(D) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (f) of this section for a PAL for that pollutant. Instead, the definition at paragraph (f)(2)(viii) of this section shall apply.

(vi)(A) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*1*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(ii) of this section; and

(*2*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (a)(1)(vi)(A)(*2*) shall be determined as provided in paragraph (a)(1)(xxxv) of this section, except that paragraphs (a)(1)(xxxv)(A)(*3*) and (a)(1)(xxxv)(B)(*4*) of this section shall not apply.

* * * * *

(C) An increase or decrease in actual emissions is creditable only if:

(*1*) It occurs within a reasonable period to be specified by the reviewing authority; and

(*2*) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*3*) The increase or decrease in emissions did not occur at a Clean Unit, except as provided in paragraphs (c)(8) and (d)(10) of this section.

* * * * *

(E) * * *

(*2*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins; and

* * * * *

(*4*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*5*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under 40 CFR 52.21(y) or under regulations approved pursuant to paragraph (d) of this section or § 51.166(u). That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the Clean Unit designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emissions reductions that were not relied upon in a PCP excluded pursuant to paragraph (e) of this section or for a Clean Unit designation are creditable to the extent they meet the requirements in paragraphs (e)(6)(iv) of this section for the PCP and paragraphs (c)(8) or (d)(10) of this section for a Clean Unit.

* * * * *

(G) Paragraph (a)(1)(xii)(B) of this section shall not apply for determining creditable increases and decreases or after a change.

* * * * *

(vii) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric steam generating unit as defined in paragraph (a)(1)(xx) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (a)(1)(vii)(A) and (B) of this section.

(A) A new emissions unit is any emissions unit which is (or will be) newly constructed and which has existed for less than 2 years from the date such emissions unit first operated.

(B) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (a)(1)(vii)(A) of this section.

* * * * *

(xii)(A) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (a)(1)(xii)(B) through (D) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (f) of this section. Instead, paragraphs (a)(1)(xxviii) and (xxxv) of this section shall apply for those purposes.

(B) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(C) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(D) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(xiii) *Lowest achievable emission rate (LAER)* means, for any source, the more stringent rate of emissions based on the following: * * *

* * * * *

(xviii) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(xxi) [Reserved]

* * * * *

(xxv) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (a)(1)(xxvi) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (a)(1)(xxv)(A) through (F) of this section are presumed to be environmentally beneficial pursuant to paragraph (e)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (e)(2) and (e)(5) of this section.

(A) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(B) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(C) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(D) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(E) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*1*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*2*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*3*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*4*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*5*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(F) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP), including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (a)(1)(xxv)(F)(*1*) and (*2*) of this section.

(*1*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*2*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (a)(1)(xxv)(F)(*2*)(*i*) through (*iv*) of this section.

(*i*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*ii*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*iii*) Calculate the projected ODP-weighted amount by multiplying the projected future annual usage of the new substance by its ODP.

(*iv*) If the value calculated in paragraph (a)(1)(xxv)(F)(*2*)(*ii*) of this section is more than the value calculated in paragraph (a)(1)(xxv)(F)(*2*)(*iii*) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(xxvi) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(xxvii) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (a)(1)(x) of this section) for that pollutant.

(xxviii)(A) *Projected actual emissions* means, the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(B) In determining the projected actual emissions under paragraph (a)(1)(xxviii)(A) of this section before beginning actual construction, the owner or operator of the major stationary source:

(*1*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan; and

(*2*) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; and

(*3*) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (a)(1)(xxxv) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

(*4*) In lieu of using the method set out in paragraphs (a)(1)(xxviii)(B)(*1*) through (*3*) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (a)(1)(iii) of this section.

(xxix) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, that is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved by the Administrator in accordance with paragraph (c) of this section; or any emissions unit that has been designated by a reviewing authority as a Clean Unit, based on the criteria in paragraphs (d)(3)(i) through (iv) of this section, using a plan-approved permitting process; or any emissions unit that has been designated as a Clean Unit by the Administrator in accordance with § 52.21(y)(3)(i) through (iv) of this chapter.

(xxx) *Nonattainment major new source review (NSR) program* means a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of this section, or a program that implements part 51, appendix S, Sections I through VI of this chapter. Any permit issued under such a program is a major NSR permit.

(xxxi) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(xxxii) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(xxxiii) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(xxxiv) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(xxxv) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (a)(1)(xxxv)(A) through (D) of this section.

(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*1*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*2*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

(*3*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each regulated NSR pollutant.

(*4*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (a)(1)(xxxv)(A)(*2*) of this section.

(B) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority for a permit required either under this section or under a plan approved by the Administrator, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*1*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*2*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*3*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of paragraph (a)(3)(ii)(G) of this section.

(*4*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*5*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (a)(1)(xxxv)(B)(*2*) and (*3*) of this section.

(C) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(D) For a PAL for a major stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (a)(1)(xxxv)(A) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (a)(1)(xxxv)(B) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (a)(1)(xxxv)(C) of this section.

(xxxvi) [Reserved]

(xxxvii) *Regulated NSR pollutant,* for purposes of this section, means the following:

(A) Nitrogen oxides or any volatile organic compounds;

(B) Any pollutant for which a national ambient air quality standard has been promulgated; or

(C) Any pollutant that is a constituent or precursor of a general pollutant listed under paragraphs (a)(1)(xxxvii)(A) or (B) of this section, provided that a constituent or precursor pollutant may only be regulated under NSR as part of regulation of the general pollutant.

(xxxviii) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under this section and § 51.166, or the Administrator in the case of EPA-implemented permit programs under § 52.21.

(xxxix) *Project* means a physical change in, or change in the method of operation of, an existing major stationary source.

(XL) *Best available control technology (BACT)* means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the reviewing authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR part 60 or 61. If the reviewing authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

(XLi) *Prevention of Significant Deterioration (PSD) permit* means any permit that is issued under a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of § 51.166 of this chapter, or under the program in § 52.21 of this chapter.

(XLii) *Federal Land Manager* means, with respect to any lands in the United States, the Secretary of the department with authority over such lands.

(2) *Applicability procedures.* (i) Each plan shall adopt a preconstruction review program to satisfy the requirements of sections 172(c)(5) and 173 of the Act for any area designated nonattainment for any national ambient air quality standard under subpart C of 40 CFR part 81. Such a program shall apply to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment under section 107(d)(1)(A)(i) of the Act, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(ii) Each plan shall use the specific provisions of paragraphs (a)(2)(ii)(A) through (F) of this section. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(2)(ii)(A) through (F) of this section.

(A) Except as otherwise provided in paragraphs (a)(2)(iii) and (iv) of this section, and consistent with the definition of major modification contained in paragraph (a)(1)(v)(A) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (a)(1)(xxvii) of this section), and a significant net emissions increase (as defined in paragraphs (a)(1)(vi) and (x) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(B) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(ii)(C) through (F) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (a)(1)(vi) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(C) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (a)(1)(xxviii) of this section) and the baseline actual emissions (as defined in paragraphs (a)(1)(xxxv)(A) and (B) of this section, as applicable), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(D) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (a)(1)(iii) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (a)(1)(xxxv)(C) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(E) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(F) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(ii)(C) through (E) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(ii)(C) of this section for the existing unit and using the method specified in paragraph (a)(2)(ii)(E) of this section for the Clean Unit.

(iii) The plan shall require that for any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with requirements under paragraph (f) of this section.

(iv) The plan shall require that an owner or operator undertaking a PCP (as defined in paragraph (a)(1)(xxv) of this section) shall comply with the requirements under paragraph (e) of this section.

(3) * * *

(ii) * * *

(H) Decreases in actual emissions resulting from the installation of add-on control technology or application of pollution prevention measures that were relied upon in designating an emissions unit as a Clean Unit or a project as a PCP cannot be used as offsets.

(I) Decreases in actual emissions occurring at a Clean Unit cannot be used as offsets, except as provided in paragraphs (c)(8) and (d)(10) of this section. Similarly, decreases in actual emissions occurring at a PCP cannot be used as offsets, except as provided in paragraph (e)(6)(iv) of this section.

(J) The total tonnage of increased emissions, in tons per year, resulting from a major modification that must be offset in accordance with section 173 of the Act shall be determined by summing the difference between the allowable emissions after the modification (as defined by paragraph (a)(1)(xi) of this section) and the actual emissions before the modification (as defined in paragraph (a)(1)(xii) of this section) for each emissions unit.

* * * * *

(6) Each plan shall provide that the following specific provisions apply to projects at existing emissions units at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (a)(1)(xxviii)(B)(*1*) through (*3*) of this section for calculating projected actual emissions. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(6)(i) through (v) of this section.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(A) A description of the project;

(B) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (a)(1)(xxviii)(B)(*3*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (a)(6)(i) of this section to the reviewing authority. Nothing in this paragraph (a)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the reviewing authority before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions units identified in paragraph (a)(6)(i)(B) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority within 60 days after the end of each year during which records must be generated under paragraph (a)(6)(iii) of this section setting out the unit's annual emissions during the year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority if the annual emissions, in tons per year, from the project identified in paragraph (a)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (a)(6)(i)(C) of this section, by a significant amount (as defined in paragraph (a)(1)(x) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (a)(6)(i)(C) of this section. Such report shall be submitted to the reviewing authority within 60 days after the end of such year. The report shall contain the following:

(A) The name, address and telephone number of the major stationary source;

(B) The annual emissions as calculated pursuant to paragraph (a)(6)(iii) of this section; and

(C) Any other information that the owner or operator wishes to include in the report (*e.g.*, an explanation as to why the emissions differ from the preconstruction projection).

(7) Each plan shall provide that the owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (a)(6) of this section available for review upon a request for inspection by the reviewing authority or the general public pursuant to the requirements contained in §70.4(b)(3)(viii) of this chapter.

* * * * *

(c) *Clean Unit Test for emissions units that are subject to LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (c)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (c) apply to any emissions unit for which the reviewing authority has issued a major NSR permit within the past 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (c)(2)(i) through (v) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (c)(4) of this section) and before the expiration date (as determined in accordance with paragraph (c)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with LAER and the project would not alter any physical or operational characteristics that formed the basis for the LAER determination as specified in paragraph (c)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with LAER or the project would alter any physical or operational characteristics that formed the basis for the LAER determination as specified in paragraph (c)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit requalifies as a Clean Unit pursuant to paragraph (c)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(ii)(A) through (D) and paragraph (a)(2)(ii)(F) of this section as if the emissions unit is not a Clean Unit.

(v) *Certain Emissions Units with PSD permits.* For emissions units that meet the requirements of paragraphs (c)(2)(v)(A) and (B) of this section, the BACT level of emissions reductions and/or work practice requirements shall satisfy the requirement for LAER in meeting the requirements for Clean Units under paragraphs (c)(3) through (8) of this section. For these emissions units, all requirements for the LAER determination under paragraphs (c)(2)(ii) and (iii) of this section shall also apply to the BACT permit terms and conditions. In addition, the requirements of paragraph (c)(7)(i)(B) of this section do not apply to emissions units that qualify for Clean Unit status under this paragraph (c)(2)(v).

(A) The emissions unit must have received a PSD permit within the last 10 years and such permit must require the emissions unit to comply with BACT.

(B) The emissions unit must be located in an area that was redesignated as nonattainment for the relevant pollutant(s) after issuance of the PSD permit and before the effective date of the Clean Unit Test provisions in the area.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit automatically qualifies as a Clean Unit when the unit meets the criteria in paragraphs (c)(3)(i) and (ii) of this section. After the original Clean Unit designation expires in accordance with paragraph (c)(5) of this section or is lost pursuant to paragraph (c)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (c)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (d) of this section. To re-qualify as a Clean Unit under paragraph (c)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable nonattainment major NSR program and meet all the criteria in paragraph (c)(3)(iii) of this section. Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the past 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of an air pollution control technology (which includes pollution prevention as defined under paragraph (a)(1)(xxvi) of this section or work practices) that meets both the following requirements in paragraphs (c)(3)(ii)(A) and (B) of this section.

(A) The control technology achieves the LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for Clean Unit designation if the LAER determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(B) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day LAER, and the emissions unit must meet the requirements in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (c)(4)(i) or (c)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing a new control technology to meet current-day LAER.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the plan and become effective for the State in which the unit is located.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (c)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day LAER.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (c)(3)(i) and (ii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining Clean Unit designation in paragraph (c)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (c)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit Designation in paragraph (c)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions in paragraphs (c)(6)(i) through (vi) of this section related to the Clean Unit.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this Clean Unit designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.*, because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with the LAER, and any physical or operational characteristics that formed the basis for the LAER determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (c)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (c)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (c)(7)(i) through (iii) of this section. This paragraph (c)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the LAER that is recorded in the major NSR permit, and subsequently reflected in the title V permit.

(A) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the LAER determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(B) The Clean Unit may not emit above a level that has been offset.

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Offsets and netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), or be used for generating offsets unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then, the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(d) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (d)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (d) apply to emissions units which do not qualify as Clean Units under paragraph (c) of this section, but which are achieving a level of emissions control comparable to LAER, as determined by the reviewing authority in accordance with this paragraph (d).

(2) *General provisions for Clean Units.* The provisions in paragraphs (d)(2)(i) through (iv) of this section apply to a Clean Unit (designated under this paragraph (d)).

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (d)(5) of this section) and before the expiration date (as determined in accordance with paragraph (d)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (d)(4) of this section) to be comparable to LAER, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER as specified in paragraph (d)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (d)(4) of this section) to be comparable to LAER, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER as specified in paragraph (d)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (d)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(ii)(A) through (D) and paragraph (a)(2)(ii)(F) of this section as if the emissions unit were never a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (d)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (d)(6) of this section or is lost pursuant to paragraph (d)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (d)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (c) of this section. To re-qualify as a Clean Unit under paragraph (d)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (d)(7) and (8) of this section and meet all the criteria in paragraph (d)(3)(iv) of this section. The reviewing authority will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (a)(1)(xxvi) of this section or work practices) that meets both the following requirements in paragraphs (d)(3)(i)(A) and (B) of this section.

(A) The owner or operator has demonstrated that the emissions unit's control technology is comparable to LAER according to the requirements of paragraph (d)(4) of this section. However, the emissions unit is not eligible for the Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.*, if the LAER determinations to which it is compared have resulted in a determination that no control measures are required).

(B) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The reviewing authority must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before the effective date of plan requirements to implement the requirements of this paragraph (d)(3)(iii). However, for such emissions units, the owner or operator must apply for the Clean Unit designation within 2 years after the plan requirements become effective. For technologies installed after the plan requirements become effective, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (d)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day LAER, and the emissions unit must meet the requirements in paragraphs (d)(3)(i)(A) and (d)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to LAER.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to LAER for purposes of paragraph (d)(3)(i) of this section according to either paragraph (d)(4)(i) or (ii) of this section. Paragraph (d)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous LAER determinations.* The administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to LAER if it achieves an emission limitation that is at least as stringent as any one of the five best-performing similar sources for which a LAER determination has been made within the preceding 5 years, and for which information has been entered into the RBLC. The reviewing authority shall also compare this presumption to any additional LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to LAER is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as LAER. In addition, any other person may present evidence related to whether the control technology is substantially as effective as LAER during the public participation process required under paragraph (d)(7) of this section. The reviewing authority shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as LAER.

(iii) *Time of comparison.*

(A) *Emissions units with control technologies that are installed before the effective date of plan requirements implementing this paragraph.* The owner or operator of an emissions unit whose control technology is installed before the effective date of plan requirements implementing this paragraph (d) may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the LAER requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day LAER requirements. The expiration date of the Clean Unit designation will depend on which option the owner or

ED_001598_00027467

operator uses, as specified in paragraph (d)(6) of this section.

(B) *Emissions units with control technologies that are installed after the effective date of plan requirements implementing this paragraph.* The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day LAER requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major modification) is the date that the permit required by paragraph (d)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the LAER requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (d)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (d)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The reviewing authority shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (d)(8).

(8) *Required permit content.* The permit required by paragraph (d)(7) of this section shall include the terms and conditions set forth in paragraphs (d)(8)(i) through (vi) of this section. Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to LAER, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to LAER (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (d)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (d)(9) of this section.

(9) *Maintaining Clean Unit designation.* To maintain Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (d)(9)(i) through (v) of this section. This paragraph (d)(9) applies independently to each pollutant for which the reviewing authority has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to LAER.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to LAER (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) The Clean Unit may not emit above a level that has been offset.

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Offsets and Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), or be used for generating offsets unless such use occurs before the effective date of plan requirements adopted to implement this paragraph (d) or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of

determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (c)(2)(iii) and (d)(2)(iii) of this section, it must re-qualify under the requirements that are currently applicable.

(e) *PCP exclusion procedural requirements.* Each plan shall include provisions for PCPs equivalent to those contained in paragraphs (e)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the reviewing authority if the project is listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, or if the project is not listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the reviewing authority consistent with the requirements in paragraph (e)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (e)(2) of this section, and the notice or permit application must contain the information required in paragraph (e)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements in paragraphs (e)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emission reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (a)(1)(xxv)(A) through (F) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the reviewing authority, the owner or operator must include, at a minimum, the information listed in paragraphs (e)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(2)(ii) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (e)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (e)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (e)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant which will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the reviewing authority (unless otherwise prohibited under requirements of the applicable plan). The owner or operator shall respond to any requests by its reviewing authority for additional information that the reviewing authority determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (a)(1)(xxv)(A) through (F) of this section, the project must be approved by the reviewing authority and recorded in a plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The reviewing authority must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (e)(6)(i) through (iii) of this section.

(i) *General duty.* The owner or operator must operate the PCP in a manner consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (e)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (e)(3) of this section, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (e)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of emission reduction credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase, or be used for generating offsets, unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation). The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(f) *Actuals PALs.* The plan shall provide for PALs according to the provisions in paragraphs (f)(1) through (15) of this section.

(1) *Applicability.*

(i) The reviewing authority may approve the use of an actuals PAL for any existing major stationary source (except as provided in paragraph (f)(1)(ii) of this section) if the PAL meets the requirements in paragraphs (f)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (f) of this section.

(ii) The reviewing authority shall not allow an actuals PAL for VOC or NO_X for any major stationary source located in an extreme ozone nonattainment area.

(iii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (f)(1) through (15) of this section, and complies with the PAL permit:

(A) Is not a major modification for the PAL pollutant;

(B) Does not have to be approved through the plan's nonattainment major NSR program; and

(C) Is not subject to the provisions in paragraph (a)(5)(ii) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the nonattainment major NSR program).

(iv) Except as provided under paragraph (f)(1)(iii)(C) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* The plan shall use the definitions in paragraphs (f)(2)(i) through (xi) of this section for the purpose of developing and implementing regulations that authorize the use of actuals PALs consistent with paragraphs (f)(1) through (15) of this section. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (a)(1) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (a)(1)(xxxv) of this section) of all emissions units (as defined in paragraph (a)(1)(vii) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (a)(1)(xi) of this section, except as this definition is modified according to paragraphs (f)(2)(ii)(A) through (B) of this section.

(A) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(B) An emissions unit's potential to emit shall be determined using the definition in paragraph (a)(1)(iii) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (a)(1)(x) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(A) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(B) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (f)(1) through (f)(15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit which is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (a)(1)(v) and (vi) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the plan, or the title V permit issued by the reviewing authority that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (a)(1)(x) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (f)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information to the reviewing authority for approval:

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (f)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The plan allows the reviewing authority to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (f)(4)(i)(A) through (G) of this section are met.

(A) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(B) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (f)(5) of this section.

(C) The PAL permit shall contain all the requirements of paragraph (f)(7) of this section.

(D) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(E) Each PAL shall regulate emissions of only one pollutant.

(F) Each PAL shall have a PAL effective period of 10 years.

(G) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (f)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant, which occur during the PAL effective period, creditable as decreases for purposes of offsets under paragraph (a)(3)(ii) of this section unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirement for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The reviewing authority must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (a)(1)(xxxv) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (a)(1)(x) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The plan shall require that the PAL permit contain, at a minimum, the information in paragraphs (f)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (f)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the reviewing authority.

(iv) A requirement that emission calculations for compliance purposes include emissions from startups, shutdowns and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (f)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (f)(13)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (f)(12) of this section.

(viii) A requirement to retain the records required under paragraph (f)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (f)(14) of this section by the required deadlines.

(x) Any other requirements that the reviewing authority deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The plan shall require the information in paragraphs (f)(8)(i) and (ii) of this section.

(i) *PAL effective period.* The reviewing authority shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(A) During the PAL effective period, the plan shall require the reviewing authority to reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL.

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under paragraph (a)(3)(ii) of this section.

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (f)(11) of this section.

(B) The plan shall provide the reviewing authority discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date.

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the plan.

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(C) Except for the permit reopening in paragraph (f)(8)(ii)(A)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of paragraph (f)(5) of this section.

(9) *Expiration of a PAL.* Any PAL which is not renewed in accordance with the procedures in paragraph (f)(10) of this section shall expire at the end of the PAL effective period, and the requirements in paragraphs (f)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (f)(9)(i)(A) through (B) of this section.

(A) Within the time frame specified for PAL renewals in paragraph (f)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the reviewing authority) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (f)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(B) The reviewing authority shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the reviewing authority determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The reviewing authority may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the reviewing authority issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (f)(9)(i)(A) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to the nonattainment major NSR requirements if such change meets the definition of major modification in paragraph (a)(1)(v) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (a)(5)(ii) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (f)(1)(iii)(C) of this section.

(10) *Renewal of a PAL.*

(i) The reviewing authority shall follow the procedures specified in paragraph (f)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the reviewing authority.

(ii) *Application deadline.* The plan shall require that a major stationary source owner or operator shall submit a timely application to the reviewing authority to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (f)(10)(iii)(A) through (D) of this section.

(A) The information required in paragraphs (f)(3)(i) through (iii) of this section.

(B) A proposed PAL level.

(C) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(D) Any other information the owner or operator wishes the reviewing authority to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the reviewing authority shall consider the options outlined in paragraphs (f)(10)(iv)(A) and (B) of this section. However, in no case may any such adjustment fail to comply with paragraph (f)(10)(iv)(C) of this section.

(A) If the emissions level calculated in accordance with paragraph (f)(6) of this section is equal to or greater than 80 percent of the PAL level, the reviewing authority may renew the PAL at the same level without considering the factors set forth in paragraph (f)(10)(iv)(B) of this section; or

(B) The reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale.

(C) Notwithstanding paragraphs (f)(10)(iv)(A) and (B) of this section,

(*1*) If the potential to emit of the major stationary source is less than the PAL, the reviewing authority shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The reviewing authority shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (f)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the reviewing authority has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The plan shall require that the reviewing authority may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (f)(11)(i)(A) through (D) of this section.

(A) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(B) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(C) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (f)(11)(i)(A) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the nonattainment major NSR program process (for example, LAER), even though they have also become subject to the PAL or continue to be subject to the PAL.

(D) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The reviewing authority shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (f)(11)(i)(B)), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (f)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) General Requirements.

(A) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(B) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (f)(12)(ii)(A) through (D) of this section and must be approved by the reviewing authority.

(C) Notwithstanding paragraph (f)(12)(i)(B) of this section, you may also employ an alternative monitoring approach that meets paragraph (f)(12)(i)(A) of this section if approved by the reviewing authority.

(D) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum Performance Requirements for Approved Monitoring Approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (f)(12)(iii) through (ix) of this section:

(A) Mass balance calculations for activities using coatings or solvents;

(B) CEMS;

(C) CPMS or PEMS; and

(D) Emission Factors.

(iii) Mass Balance Calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(A) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(B) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(C) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the reviewing authority determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(A) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(B) CEMS must sample, analyze and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(A) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(B) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the reviewing authority, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(A) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(B) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(C) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (f)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the reviewing authority shall, at the time of permit issuance:

(A) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(B) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the reviewing authority. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (f) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus 5 years:

(A) A copy of the PAL permit application and any applications for revisions to the PAL; and

(B) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the reviewing authority in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (f)(14)(i) through (iii).

(i) Semi-Annual Report. The semi-annual report shall be submitted to the reviewing authority within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (f)(14)(i)(A) through (G) of this section.

(A) The identification of owner and operator and the permit number.

(B) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (f)(13)(i) of this section.

(C) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(D) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(E) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(F) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by paragraph (f)(12)(vii) of this section.

(G) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) Deviation report. The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(A) The identification of owner and operator and the permit number;

(B) The PAL requirement that experienced the deviation or that was exceeded;

(C) Emissions resulting from the deviation or the exceedance; and

(D) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) Re-validation results. The owner or operator shall submit to the reviewing authority the results of any re-validation test or method within 3 months after completion of such test or method.

(15) *Transition requirements.*

(i) No reviewing authority may issue a PAL that does not comply with the requirements in paragraphs (f)(1) through (15) of this section after the Administrator has approved regulations incorporating these requirements into a plan.

(ii) The reviewing authority may supersede any PAL which was established prior to the date of approval of the plan by the Administrator with a PAL that complies with the requirements of paragraphs (f)(1) through (15) of this section.

(g) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

5. In 40 CFR 51.166(b)(1)(i)(*b*) and (b)(5), remove the words "any air pollutant subject to regulation under the Act," and add, in their place, the words "a regulated NSR pollutant."

6. In addition to the amendments set forth above, section 51.166 is amended:

a. By revising paragraph (a)(1).

b. By revising paragraph (a)(6)(i).

c. By adding paragraph (a)(7).

d. By revising paragraphs (b)(2)(i) and (ii).

e. By revising paragraph (b)(2)(iii)(*h*).

f. By adding paragraph (b)(2)(iv).

g. By revising paragraph (b)(3)(i).

h. By revising paragraphs (b)(3)(iii) and (iv).

i. By revising paragraphs (b)(3)(vi)(*b*) and (*c*).

j. By adding paragraph (b)(3)(vi)(*d*).

k. By adding paragraph (b)(3)(viii).

l. By revising paragraphs (b)(7) and (8).

m. By revising paragraph (b)(13).

n. By revising paragraph (b)(21).

o. By removing the following from paragraph (b)(23)(i): Asbestos: 0.007 tpy; Beryllium: 0.0004 tpy; Mercury: 0.1 tpy; and Vinyl Chloride: 1 tpy.

p. By revising paragraph (b)(31).

q. By reserving paragraph (b)(32).

r. By adding paragraphs (b)(38) through (52).

s. By revising the introductory text of paragraph (i).

t. By removing paragraphs (i)(1) through (3).

u. By re-designating paragraphs (i)(4) through (12) as paragraphs (i)(1) through (9).

v. By revising newly redesignated paragraphs (i)(5)(i)(*g*) through (*j*).

w. By removing newly redesignated paragraphs (i)(5)(i)(*k*) through (*m*).

x. By adding paragraphs (r)(3) through (7).

y. By adding paragraphs (t) through (x).

7. In addition to the amendments set forth above, in 40 CFR 51.166, remove the words ''pollutant subject to regulation under the Act'' and add, in their place, the words ''a regulated NSR pollutant'' in the following places:

a. (b)(1)(i)(*a*);

c. (b)(12);

d. (b)(23)(ii);

e. newly redesignated (i)(4); and

f. (j)(2) and (3).

The revisions and additions read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

(a)(1) *Plan requirements.* In accordance with the policy of section 101(b)(1) of the Act and the purposes of section 160 of the Act, each applicable State Implementation Plan and each applicable Tribal Implementation Plan shall contain emission limitations and such other measures as may be necessary to prevent significant deterioration of air quality.

* * * * *

(6) * * *

(i) Any State required to revise its implementation plan by reason of an amendment to this section, including any amendment adopted simultaneously with this paragraph (a)(6)(i), shall adopt and submit such plan revision to the Administrator for approval no later than three years after such amendment is published in the **Federal Register**.

* * * * *

(7) *Applicability.* Each plan shall contain procedures that incorporate the requirements in paragraphs (a)(7)(i) through (vi) of this section.

(i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

(iii) No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements.

(iv) Each plan shall use the specific provisions of paragraphs (a)(7)(iv)(*a*) through (*f*) of this section. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (a)(7)(iv)(*a*) through (*f*) of this section.

(*a*) Except as otherwise provided in paragraphs (a)(7)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (b)(39) of this section), and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(*b*) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(7)(iv)(*c*) through (*f*) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(*c*) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(40) of this section) and the baseline actual emissions (as defined in paragraphs (b)(47)(i) and (ii) of this section) for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(47)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*e*) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(7)(iv)(*c*) through (*e*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(7)(iv)(*c*) of this section for the existing unit and determined using the method specified in paragraph (a)(7)(iv)(*e*) of this section for the Clean Unit.

(v) The plan shall require that for any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with requirements under paragraph (w) of this section.

(vi) The plan shall require that an owner or operator undertaking a PCP (as defined in paragraph (b)(31) of this section) shall comply with the requirements under paragraph (v) of this section.

* * * * *

(b) * * *

(2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(39) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(49) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(ii) Any significant emissions increase (as defined at paragraph (b)(39) of this section) from any emissions units or net emissions increase (as defined at paragraph (b)(3) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) * * *

(*h*) The addition, replacement, or use of a PCP, as defined in paragraph (b)(31) of this section, at an existing emissions unit meeting the requirements of paragraph (v) of this section. A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(iv) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (w) of this section for a PAL for that pollutant. Instead, the definition at paragraph (w)(2)(viii) of this section shall apply.

(3)(i) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*a*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(7)(iv) of this section; and

(*b*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(*b*) shall be determined as provided in paragraph (b)(47), except that paragraphs (b)(47)(i)(*c*) and (b)(47)(ii)(*d*) of this section shall not apply.

* * * * *

(iii) An increase or decrease in actual emissions is creditable only if:

(*a*) It occurs within a reasonable period (to be specified by the reviewing authority); and

(*b*) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*c*) The increase or decrease in emissions did not occur at a Clean Unit, except as provided in paragraphs (t)(8) and (u)(10) of this section.

(iv) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

* * * * *

(vi) * * *

(*b*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins;

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*d*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under § 52.21(y) or under regulations approved pursuant to paragraph (u) of this section or § 51.165(d). That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the Clean Unit designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emissions reductions that were not relied upon in a PCP excluded pursuant to paragraph (v) of this section or for the Clean Unit designation are creditable to the extent they meet the requirements in paragraph (v)(6)(iv) of this section for the PCP and paragraph (t)(8) or (u)(10) of this section for a Clean Unit.

* * * * *

(viii) Paragraph (b)(21)(ii) of this section shall not apply for determining creditable increases and decreases.

* * * * *

(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(30) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section.

(8) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(13)(i) *Baseline concentration* means that ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(*a*) The actual emissions, as defined in paragraph (b)(21) of this section, representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph (b)(13)(ii) of this section;

(*b*) The allowable emissions of major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date; and

(*b*) Actual emissions increases and decreases, as defined in paragraph (b)(21) of this section, at any stationary source occurring after the minor source baseline date.

* * * * *

(21)(i) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii) through (iv) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (w) of this section. Instead, paragraphs (b)(40) and (b)(47) of this section shall apply for those purposes.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The reviewing authority may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

* * * * *

(31) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (b)(38) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (b)(31)(i) through (vi) of this section are presumed to be environmentally beneficial pursuant to paragraph (v)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (v)(2) and (v)(5) of this section.

(i) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(ii) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(iii) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(iv) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(v) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*a*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*b*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*c*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*d*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*e*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(vi) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP), including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (b)(31)(vi)(a) and (b) of this section.

(*a*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*b*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (b)(31)(vi)(b)(1) through (4) of this section.

(*1*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*2*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*3*) Calculate the projected ODP-weighted amount by multiplying the projected annual usage of the new substance by its ODP.

(*4*) If the value calculated in paragraph (b)(31)(vi)(b)(2) of this section is more than the value calculated in paragraph (b)(31)(vi)(b)(3) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(32) [Reserved]

* * * * *

(38) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(39) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

(40)(i) *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.

(ii) In determining the projected actual emissions under paragraph (b)(40)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(*a*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved plan; and

(*b*) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(*c*) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(47) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

(*d*) In lieu of using the method set out in paragraphs (b)(40)(ii)(*a*) through (*c*) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(41) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved by the Administrator in accordance with paragraph (t) of this section; or any emissions unit that has been designated by a reviewing authority as a Clean Unit, based on the criteria in paragraphs (u)(3)(i) through (iv) of this section, using a plan-approved permitting process; or any emissions unit that has been designated as a Clean Unit by the Administrator in accordance with 52.21 (y)(3)(i) through (iv) of this chapter.

(42) *Prevention of Significant Deterioration Program (PSD) program* means a major source preconstruction permit program that has been approved by the Administrator and incorporated into the plan to implement the requirements of this section, or the program in § 52.21 of this chapter. Any permit issued under such a program is a major NSR permit.

(43) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(44) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O^2 or CO^2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(45) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O^2 or CO^2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(46) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(47) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(47)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*d*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(47)(i)(*b*) of this section.

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the reviewing authority for a permit required either under this section or under a plan approved by the Administrator, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of § 51.165(a)(3)(ii)(G).

(*d*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*e*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(47)(ii)(b) and (c) of this section.

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(47)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(47)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(47)(iii) of this section.

(48) [Reserved]

(49) *Regulated NSR pollutant,* for purposes of this section, means the following:

(i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (*e.g.*, volatile organic compounds are precursors for ozone);

(ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;

(iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

(50) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under § 51.165 and this section, or the Administrator in the case of EPA-implemented permit programs under § 52.21 of this chapter.

(51) *Project* means a physical change in, or change in method of operation of, an existing major stationary source.

(52) *Lowest achievable emission rate (LAER)* is as defined in § 51.165(a)(1)(xiii).

* * * * *

(i) *Exemptions.*

* * * * *

(5) * * *

(i) * * *

(*g*) Fluorides—0.25 $\mu g/m^3$, 24-hour average;

(*h*) Total reduced sulfur—10 $\mu g/m^3$, 1-hour average

(*i*) Hydrogen sulfide—0.2 $\mu g/m^3$, 1-hour average;

(*j*) Reduced sulfur compounds—10 $\mu g/m^3$, 1-hour average; or

* * * * *

(r) * * *

(3) [Reserved]

(4) [Reserved]

(5) [Reserved]

(6) Each plan shall provide that the following specific provisions apply to projects at existing emissions units at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (b)(40)(ii)(*a*) through (*c*) of this section for calculating projected actual emissions. Deviations from these provisions will be approved only if the State specifically demonstrates that the submitted provisions are more stringent than or at least as stringent in all respects as the corresponding provisions in paragraphs (r)(6)(i) through (v) of this section.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(*a*) A description of the project;

(*b*) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(*c*) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(40)(ii)(*c*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i) of this section to the reviewing authority. Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the reviewing authority before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(*b*) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the reviewing authority if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section) by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section. Such report shall be submitted to the reviewing authority within 60 days after the end of such year. The report shall contain the following:

(*a*) The name, address and telephone number of the major stationary source;

(*b*) The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

(*c*) Any other information that the owner or operator wishes to include in the report (*e.g.*, an explanation as to why the emissions differ from the preconstruction projection).

(7) Each plan shall provide that the owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon request for inspection by the reviewing authority or the general public pursuant to the requirements contained in § 70.4(b)(3)(viii) of this chapter.

* * * * *

(t) *Clean Unit Test for emissions units that are subject to BACT or LAER.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (t)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (t) apply to any emissions unit for which the reviewing authority has issued a major NSR permit within the past 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (t)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (t)(4) of this section) and before the expiration date (as determined in accordance with paragraph (t)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT and the project would not alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (t)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or the project would alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (t)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (t)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(7)(iv)(*a*) through (*d*) and paragraph (a)(7)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit Applicability Test.* An emissions unit automatically qualifies as a Clean Unit when the unit meets the criteria in paragraphs (t)(3)(i) and (ii) of this section. After the original Clean Unit designation expires in accordance with paragraph (t)(5) of this section or is lost pursuant to paragraph (t)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (t)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (u) of this section. To re-qualify as a Clean Unit under paragraph (t)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable PSD program and meet all the criteria in paragraph (t)(3)(iii) of this section. The Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the past 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(38) of this section or work practices) that meets both the following requirements in paragraphs (t)(3)(ii)(*a*) and (*b*) of this section.

(*a*) The control technology achieves the BACT or LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for the Clean Unit designation if the BACT determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day BACT (or LAER), and the emissions unit must meet the requirements in paragraphs (t)(3)(i) and (t)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (t)(4)(i) or (t)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing a new control technology to meet current-day BACT.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than the date that provisions for the Clean Unit applicability test are approved by the Administrator for incorporation into the plan and become effective for the State in which the unit is located.

(ii) *Emissions Units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (t)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day BACT.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (t)(3)(i) and (ii) of this section or re-qualifies by implementing new control technology to meet current-day BACT under paragraph (t)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (t)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (t)(3)(iii) of this section using an existing control technology, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (t)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions related to the Clean Unit in paragraphs (t)(6)(i) through (vi) of this section.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this Clean Unit designation applies.

(ii) The effective date of the Clean Unit designation. If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.*, because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) The expiration date of the Clean Unit designation. If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with BACT, and any physical or operational characteristics that formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (t)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (t)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (t)(7)(i) through (iii) of this section. This paragraph (t)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the BACT that is recorded in the major NSR permit, and subsequently reflected in the title V permit. The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the BACT determination (*e.g.*, possibly the emissions unit's capacity or throughput).

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis''), unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(u) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to BACT.* The plan shall provide an owner or operator of a major stationary source the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (u)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (u) apply to emissions units which do not qualify as Clean Units under paragraph (t) of this section, but which are achieving a level of emissions control comparable to BACT, as determined by the reviewing authority in accordance with this paragraph (u).

(2) *General provisions for Clean Units.* The provisions in paragraphs (u)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (u)(5) of this section) and before the expiration date (as determined in accordance with paragraph (u)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (u)(4) of this section) to be comparable to BACT, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (u)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (u)(4) of this section) to be comparable to BACT, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (u)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (u)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(7)(iv)(*a*) through (*d*) and paragraph (a)(7)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (u)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (u)(6) of this section or is lost pursuant to paragraph (u)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (u)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (t) of this section. To re-qualify as a Clean Unit under paragraph (u)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (u)(7) and (8) of this section and meet all the criteria in paragraph (u)(3)(iv) of this section. The reviewing authority will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(38) or work practices) that meets both the following requirements in paragraphs (u)(3)(i)(*a*) and (*b*) of this section.

(*a*) The owner or operator has demonstrated that the emissions unit's control technology is comparable to BACT according to the requirements of paragraph (u)(4) of this section. However, the emissions unit is not eligible for the Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.*, if the BACT determinations to which it is compared have resulted in a determination that no control measures are required).

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The reviewing authority must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before the effective date of plan requirements to implement the requirements of this paragraph (u)(3)(iii). However, for such emissions units, the owner or operator must apply for the Clean Unit designation within 2 years after the plan requirements become effective. For technologies installed after the plan requirements become effective, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (u)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day BACT, and the emissions unit must meet the requirements in paragraphs (u)(3)(i)(*a*) and (u)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to BACT.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to BACT for purposes of paragraph (u)(3)(i) of this section according to either paragraph (u)(4)(i) or (ii) of this section. Paragraph (u)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous BACT and LAER determinations.* The Administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. The reviewing authority shall also compare this presumption to any additional BACT or LAER determinations of which it is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as BACT. In addition, any other person may present evidence related to whether the control technology is substantially as effective as BACT during the public participation process required under paragraph (u)(7) of this section. The reviewing authority shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as BACT.

(iii) *Time of comparison.*

(*a*) *Emissions units with control technologies that are installed before the effective date of plan requirements implementing this paragraph.* The owner or operator of an emissions unit whose control technology is installed before the effective date of plan requirements implementing this paragraph (u) may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (u)(6) of this section.

(*b*) Emissions units with control technologies that are installed after the effective date of plan requirements implementing this paragraph. The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major

modification) is the date that the permit required by paragraph (u)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (u)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (u)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The reviewing authority shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter, including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (u)(8) of this section.

(8) *Required permit content.* The permit required by paragraph (u)(7) of this section shall include the terms and conditions set forth in paragraphs (u)(8)(i) through (vi). Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which the Clean Unit designation applies.

(ii) The effective date of the Clean Unit designation. If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the reviewing authority of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the reviewing authority issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the reviewing authority of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to BACT, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (u)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (u)(9) of this section.

(9) *Maintaining the Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (u)(9)(i) through (v) of this section. This paragraph (u)(9) applies independently to each pollutant for which the reviewing authority has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to BACT.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) [Reserved]

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a "netting analysis") unless such use occurs before the effective date of plan requirements adopted to implement this paragraph (u) or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment designation of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (t)(2)(iii) and (u)(2)(iii) of this section, it must re-

qualify under the requirements that are currently applicable.

(v) *PCP exclusion procedural requirements.* Each plan shall include provisions for PCPs equivalent to those contained in paragraphs (v)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the reviewing authority if the project is listed in paragraphs (b)(31)(i) through (vi) of this section, or if the project is not listed in paragraphs (b)(31)(i) through (vi) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the reviewing authority consistent with the requirements in paragraph (v)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (v)(2) of this section, and the notice or permit application must contain the information required in paragraph (v)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements in paragraphs (v)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emission reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (b)(31)(i) through (vi) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the reviewing authority, the owner or operator must include, at a minimum, the information listed in paragraphs (v)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(7)(vi) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (v)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (v)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (v)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant that will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (b)(31)(i) through (vi) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the reviewing authority (unless otherwise prohibited under requirements of the applicable plan). The owner or operator shall respond to any requests by its reviewing authority for additional information that the reviewing authority determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (b)(31)(i) through (vi) of this section, the project must be approved by the reviewing authority and recorded in a plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The reviewing authority must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (v)(6)(i) through (iv) of this section.

(i) *General duty.* The owner or operator must operate the PCP consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (v)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (v)(3), and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (v)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of Emission Reduction Credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation.) The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emission limitation if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(w) *Actuals PALs.* The plan shall provide for PALs according to the provisions in paragraphs (w)(1) through (15) of this section.

(1) *Applicability.*

(i) The reviewing authority may approve the use of an actuals PAL for any existing major stationary source if the PAL meets the requirements in paragraphs (w)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (w) of this section.

(ii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (w)(1) through (15) of this section, and complies with the PAL permit:

(*a*) Is not a major modification for the PAL pollutant;

(*b*) Does not have to be approved through the plan's major NSR program; and

(*c*) Is not subject to the provisions in paragraph (r)(2) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program).

(iii) Except as provided under paragraph (w)(1)(ii)(c) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* The plan shall use the definitions in paragraphs (w)(2)(i) through (xi) of this section for the purpose of developing and implementing regulations that authorize the use of actuals PALs consistent with paragraphs (w)(1) through (15) of this section. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (b) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (b)(47) of this section) of all emissions units (as defined in paragraph (b)(7) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (b)(16) of this section, except as this definition is modified according to paragraphs (w)(2)(ii)(*a*) and (*b*) of this section.

(*a*) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(*b*) An emissions unit's potential to emit shall be determined using the definition in paragraph (b)(4) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (b)(23) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(*a*) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(*b*) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (w)(1) through (15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (b)(2) and (b)(3) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the plan, or the title V permit issued by the reviewing authority that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (b)(23) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (w)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information in paragraphs (w)(3)(i) through (iii) of this section to the reviewing authority for approval.

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations, or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown, and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (w)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The plan allows the reviewing authority to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (w)(4)(i)(a) through (g) of this section are met.

(*a*) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(*b*) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (w)(5) of this section.

(*c*) The PAL permit shall contain all the requirements of paragraph (w)(7) of this section.

(*d*) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(*e*) Each PAL shall regulate emissions of only one pollutant.

(*f*) Each PAL shall have a PAL effective period of 10 years.

(*g*) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (w)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant that occur during the PAL effective period creditable as decreases for purposes of offsets under § 51.165(a)(3)(ii) of this chapter unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirements for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased, through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the reviewing authority provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The reviewing authority must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The plan shall provide that the actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(47) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The reviewing authority shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the reviewing authority is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The plan shall require that the PAL permit contain, at a minimum, the information in paragraphs (w)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (w)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the reviewing authority.

(iv) A requirement that emission calculations for compliance purposes include emissions from startups, shutdowns and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (w)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (w)(3)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (w)(13) of this section.

(viii) A requirement to retain the records required under paragraph (w)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (w)(14) of this section by the required deadlines.

(x) Any other requirements that the reviewing authority deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The plan shall require the information in paragraphs (w)(8)(i) and (ii) of this section.

(i) *PAL effective period.* The reviewing authority shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(*a*) During the PAL effective period, the plan shall require the reviewing authority to reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL;

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under § 51.165(a)(3)(ii) of this chapter; and

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (w)(11) of this section.

(*b*) The plan shall provide the reviewing authority discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date;

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the plan; and

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an AQRV that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(*c*) Except for the permit reopening in paragraph (w)(8)(ii)(*a*)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all reopenings shall be carried out in accordance with the public participation requirements of paragraph (w)(5) of this section.

(9) *Expiration of a PAL.* Any PAL that is not renewed in accordance with the procedures in paragraph (w)(10) of this section shall expire at the end of the PAL effective period, and the

requirements in paragraphs (w)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (w)(9)(i)(*a*) and (*b*) of this section.

(*a*) Within the time frame specified for PAL renewals in paragraph (w)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the reviewing authority) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (w)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(*b*) The reviewing authority shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the reviewing authority determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The reviewing authority may approve the use of monitoring systems (source testing,emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the reviewing authority issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (w)(9)(i)(*b*) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in paragraph (b)(2) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (r)(2) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (w)(1)(ii)(c) of this section.

(10) *Renewal of a PAL.*

(i) The reviewing authority shall follow the procedures specified in paragraph (w)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the reviewing authority.

(ii) *Application deadline.* The plan shall require that a major stationary source owner or operator shall submit a timely application to the reviewing authority to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (w)(10)(iii) (*a*) through (*d*) of this section.

(*a*) The information required in paragraphs (w)(3)(i) through (iii) of this section.

(*b*) A proposed PAL level.

(*c*) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(*d*) Any other information the owner or operator wishes the reviewing authority to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the reviewing authority shall consider the options outlined in paragraphs (w)(10)(iv) (*a*) and (*b*) of this section. However, in no case may any such adjustment fail to comply with paragraph (w)(10)(iv)(*c*) of this section.

(*a*) If the emissions level calculated in accordance with paragraph (w)(6) of this section is equal to or greater than 80 percent of the PAL level, the reviewing authority may renew the PAL at the same level without considering the factors set forth in paragraph (w)(10)(iv)(*b*) of this section; or

(*b*) The reviewing authority may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the reviewing authority in its written rationale.

(*c*) Notwithstanding paragraphs (w)(10)(iv) (*a*) and (*b*) of this section:

(*1*) If the potential to emit of the major stationary source is less than the PAL, the reviewing authority shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The reviewing authority shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (w)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the reviewing authority has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The plan shall require that the reviewing authority may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (w)(11)(i) (*a*) through (*d*) of this section.

(*a*) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(*b*) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s), exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(*c*) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (w)(11)(i)(*a*) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT), even though they have also become subject to the PAL or continue to be subject to the PAL.

(*d*) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The reviewing authority shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (w)(11)(i)(*b*) of this section), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (w)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) *General requirements.*

(*a*) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(*b*) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (w)(12)(ii) (*a*) through (*d*) of this section and must be approved by the reviewing authority.

(*c*) Notwithstanding paragraph (w)(12)(i)(*b*) of this section, you may also employ an alternative monitoring approach that meets paragraph (w)(12)(i)(*a*) of this section if approved by the reviewing authority.

(*d*) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum performance requirements for approved monitoring approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (w)(12)(iii) through (ix) of this section:

(*a*) Mass balance calculations for activities using coatings or solvents;

(*b*) CEMS;

(*c*) CPMS or PEMS; and

(*d*) Emission factors.

(iii) Mass balance calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(*a*) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(*b*) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(*c*) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the reviewing authority determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(*b*) CEMS must sample, analyze, and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(*b*) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the reviewing authority, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(*b*) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(*c*) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the reviewing authority determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (w)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the reviewing authority shall, at the time of permit issuance:

(*a*) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(*b*) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the reviewing authority. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (w) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records, for the duration of the PAL effective period plus 5 years:

(*a*) A copy of the PAL permit application and any applications for revisions to the PAL; and

(*b*) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the reviewing authority in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (w)(14)(i) through (iii) of this section.

(i) *Semi-annual report.* The semi-annual report shall be submitted to the reviewing authority within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (w)(14)(i)(*a*) through (*g*) of this section.

(*a*) The identification of owner and operator and the permit number.

(*b*) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (w)(13)(i) of this section.

(*c*) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(*d*) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(*e*) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(*f*) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by paragraph (w)(12)(vii) of this section.

(*g*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) *Deviation report.* The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(*a*) The identification of owner and operator and the permit number;

(*b*) The PAL requirement that experienced the deviation or that was exceeded;

(*c*) Emissions resulting from the deviation or the exceedance; and

(*d*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) Re-validation results. The owner or operator shall submit to the reviewing authority the results of any re-validation test or method within three months after completion of such test or method.

(15) *Transition requirements.*

(i) No reviewing authority may issue a PAL that does not comply with the requirements in paragraphs (w)(1) through (15) of this section after the Administrator has approved regulations incorporating these requirements into a plan.

(ii) The reviewing authority may supersede any PAL which was established prior to the date of approval of the plan by the Administrator with a PAL that complies with the requirements of paragraphs (w)(1) through (15) of this section.

(x) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

PART 52— [AMENDED]

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A— [Amended]

2. In 40 CFR 52.21(b)(1)(i)(*b*) and (b)(5), remove the words ''any air pollutant subject to regulation under the Act,'' and add, in their place, the words ''a regulated NSR pollutant.''

3. In addition to the amendments set forth above, section 52.21 is amended:

a. By redesignating paragraph (a) as paragraph (a)(1).

b. By adding paragraph (a)(2).

c. By revising paragraphs (b)(2)(i) and (ii).

d. By revising paragraph (b)(2)(iii)(*h*).

e. By adding paragraph (b)(2)(iv).

f. By revising paragraph (b)(3)(i).

g. By revising paragraphs (b)(3)(iii) and (iv).

h. By revising paragraphs (b)(3)(vi)(*b*) and (*c*).

i. By adding paragraph (b)(3)(vi)(*d*).

j. By adding paragraph (b)(3)(ix).

k. By revising paragraphs (b)(7) and (8).

l. By revising paragraph (b)(13).

m. By revising paragraph (b)(21).

n. By removing the following items from the list in paragraph (b)(23)(i): ''Asbestos: 0.007 tpy''; ''Beryllium: 0.0004 tpy''; ''Mercury: 0.1 tpy''; and ''Vinyl Chloride: 1 tpy''.

o. By revising paragraph (b)(32).

p. By removing and reserving paragraph (b)(33).

q. By adding paragraphs (b)(39) through (48), adding and reserving paragraph (b)(49), and by adding paragraphs (b)(50) through (b)(54).

r. By revising the introductory text of paragraph (i).

s. By removing paragraphs (i)(1) through (3).

t. By redesignating paragraphs (i)(4) through (13) as paragraphs (i)(1) through (10).

u. By removing the following items from the list in newly redesignated paragraph (i)(5)(i): ''Mercury—0.25 μg/m^3, 24-hour average''; ''Beryllium—0.001 μg/m^3, 24-hour average''; ''Vinyl chloride—15 μg/m^3, 24-hour average''.

v. By adding and reserving paragraphs (r)(5) and adding paragraphs (r)(6) through (7).

w. By adding paragraphs (x) through (bb).

4. In addition to the amendments set forth above, in 40 CFR 52.21, remove the words ''pollutant subject to regulation under the Act'' and add, in their place, the words ''regulated NSR pollutant'' in the following places:

a. (b)(1)(i)(*a*);
b. (b)(2)(i);
c. (b)(23)(ii);
d. newly redesignated (i)(4); and
e. (j)(2) and (3).

The revisions and additions read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(a)(1) *Plan disapproval.* * * *

(2) *Applicability procedures.* (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

(ii) The requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

(iii) No new major stationary source or major modification to which the requirements of paragraphs (j) through (r)(5) of this section apply shall begin actual construction without a permit that states that the major stationary source or major modification will meet those requirements. The Administrator has authority to issue any such permit.

(iv) The requirements of the program will be applied in accordance with the principles set out in paragraphs (a)(2)(iv)(*a*) through (*f*) of this section.

(*a*) Except as otherwise provided in paragraphs (a)(2)(v) and (vi) of this section, and consistent with the definition of major modification contained in paragraph (b)(2) of this section, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase (as defined in paragraph (b)(40) of this section), and a significant net emissions increase (as defined in paragraphs (b)(3) and (b)(23) of this section). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

(*b*) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (*i.e.*, the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(*c*) through (*f*) of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (*i.e.*, the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(*c*) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*d*) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*e*) *Emission test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(*c*) through (*e*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section). For example, if a project involves both an existing emissions unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(iv)(*c*) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(*e*) of this section for the Clean Unit.

(v) For any major stationary source for a PAL for a regulated NSR pollutant, the major stationary source shall comply with the requirements under paragraph (aa) of this section.

(vi) An owner or operator undertaking a PCP (as defined in paragraph (b)(32) of this section) shall comply with the requirements under paragraph (z) of this section.

* * * * *

(b) * * *

(2)(i) *Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

(ii) Any significant emissions increase (as defined in paragraph (b)(40) of this section) from any emissions units or net emissions increase (as defined in paragraph (b)(3) of this section) at a major stationary source that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) * * *

(*h*) The addition, replacement, or use of a PCP, as defined in paragraph (b)(32) of this section, at an existing emissions unit meeting the requirements of paragraph (z) of this section. A replacement control technology must provide more effective emission control than that of the replaced control technology to qualify for this exclusion.

* * * * *

(iv) This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under paragraph (aa) of this section for a PAL for that pollutant. Instead, the definition at paragraph (aa)(2)(viii) of this section shall apply.

(3)(i) *Net emissions increase* means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

(*a*) The increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and

(*b*) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.

Baseline actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(*b*) shall be determined as provided in paragraph (b)(48) of this section, except that paragraphs (b)(48)(i)(*c*) and (b)(48)(ii)(*d*) of this section shall not apply.

* * * * *

(iii) An increase or decrease in actual emissions is creditable only if:

(*a*) The Administrator or other reviewing authority has not relied on it in issuing a permit for the source under this section, which permit is in effect when the increase in actual emissions from the particular change occurs; and

(*b*) The increase or decrease in emissions did not occur at a Clean Unit except as provided in paragraphs (x)(8) and (y)(10) of this section.

(iv) An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

* * * * *

(vi) * * *

(*b*) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins.

(*c*) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

(*d*) The decrease in actual emissions did not result from the installation of add-on control technology or application of pollution prevention practices that were relied on in designating an emissions unit as a Clean Unit under paragraph (y) of this section or under regulations approved pursuant to § 51.165(d) or to § 51.166(u) of this chapter. That is, once an emissions unit has been designated as a Clean Unit, the owner or operator cannot later use the emissions reduction from the air pollution control measures that the designation is based on in calculating the net emissions increase for another emissions unit (*i.e.*, must not use that reduction in a ''netting analysis'' for another emissions unit). However, any new emission reductions that were not relied upon in a PCP excluded pursuant to paragraph (z) of this section or for a Clean Unit designation are creditable to the extent they meet the requirements in paragraph (z)(6)(iv) of this section for the PCP and paragraphs (x)(8) or (y)(10) of this section for a Clean Unit.

* * * * *

(ix) Paragraph (b)(21)(ii) of this section shall not apply for determining creditable increases and decreases.

(7) *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section.

(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.

(ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section.

(8) *Construction* means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.

* * * * *

(13)(i) *Baseline concentration* means that ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

(*a*) The actual emissions, as defined in paragraph (b)(21) of this section, representative of sources in existence on the applicable minor source baseline date, except as provided in paragraph (b)(13)(ii) of this section; and

(*b*) The allowable emissions of major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

(ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

(*a*) Actual emissions, as defined in paragraph (b)(21) of this section, from any major stationary source on which construction commenced after the major source baseline date; and

(*b*) Actual emissions increases and decreases, as defined in paragraph (b)(21) of this section, at any stationary source occurring after the minor source baseline date.

* * * * *

(21)(i) *Actual emissions* means the actual rate of emissions of a regulated NSR pollutant from an emissions unit, as determined in accordance with paragraphs (b)(21)(ii) through (iv) of this section, except that this definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under paragraph (aa) of this section. Instead, paragraphs (b)(41) and (b)(48) of this section shall apply for those purposes.

(ii) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(iii) The Administrator may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(iv) For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

* * * * *

(32) *Pollution control project (PCP)* means any activity, set of work practices or project (including pollution prevention as defined under paragraph (b)(39) of this section) undertaken at an existing emissions unit that reduces emissions of air pollutants from such unit. Such qualifying activities or projects can include the replacement or upgrade of an existing emissions control technology with a more effective unit. Other changes that may occur at the source are not considered part of the PCP if they are not necessary to reduce emissions through the PCP. Projects listed in paragraphs (b)(32)(i) through (vi) of this section are presumed to be environmentally beneficial pursuant to paragraph (z)(2)(i) of this section. Projects not listed in these paragraphs may qualify for a case-specific PCP exclusion pursuant to the requirements of paragraphs (z)(2) and (z)(5) of this section.

(i) Conventional or advanced flue gas desulfurization or sorbent injection for control of SO_2.

(ii) Electrostatic precipitators, baghouses, high efficiency multiclones, or scrubbers for control of particulate matter or other pollutants.

(iii) Flue gas recirculation, low-NO_X burners or combustors, selective non-catalytic reduction, selective catalytic reduction, low emission combustion (for IC engines), and oxidation/absorption catalyst for control of NO_X.

(iv) Regenerative thermal oxidizers, catalytic oxidizers, condensers, thermal incinerators, hydrocarbon combustion flares, biofiltration, absorbers and adsorbers, and floating roofs for storage vessels for control of volatile organic compounds or hazardous air pollutants. For the purpose of this section, ''hydrocarbon combustion flare'' means either a flare used to comply with an applicable NSPS or MACT standard (including uses of flares during startup, shutdown, or malfunction permitted under such a standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

(v) Activities or projects undertaken to accommodate switching (or partially switching) to an inherently less polluting fuel, to be limited to the following fuel switches:

(*a*) Switching from a heavier grade of fuel oil to a lighter fuel oil, or any grade of oil to 0.05 percent sulfur diesel (*i.e.*, from a higher sulfur content #2 fuel or from #6 fuel, to CA 0.05 percent sulfur #2 diesel);

(*b*) Switching from coal, oil, or any solid fuel to natural gas, propane, or gasified coal;

(*c*) Switching from coal to wood, excluding construction or demolition waste, chemical or pesticide treated wood, and other forms of ''unclean'' wood;

(*d*) Switching from coal to #2 fuel oil (0.5 percent maximum sulfur content); and

(*e*) Switching from high sulfur coal to low sulfur coal (maximum 1.2 percent sulfur content).

(vi) Activities or projects undertaken to accommodate switching from the use of one ozone depleting substance (ODS) to the use of a substance with a lower or zero ozone depletion potential (ODP,) including changes to equipment needed to accommodate the activity or project, that meet the requirements of paragraphs (b)(32)(vi)(*a*) and (*b*) of this section.

(*a*) The productive capacity of the equipment is not increased as a result of the activity or project.

(*b*) The projected usage of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS. To make this determination, follow the procedure in paragraphs (b)(32)(vi)(*b*)(*1*) through (*4*) of this section.

(*1*) Determine the ODP of the substances by consulting 40 CFR part 82, subpart A, appendices A and B.

(*2*) Calculate the replaced ODP-weighted amount by multiplying the baseline actual usage (using the annualized average of any 24 consecutive months of usage within the past 10 years) by the ODP of the replaced ODS.

(*3*) Calculate the projected ODP-weighted amount by multiplying the projected actual usage of the new substance by its ODP.

(*4*) If the value calculated in paragraph (b)(32)(vi)(*b*)(*2*) of this section is more than the value calculated in paragraph (b)(32)(vi)(*b*)(*3*) of this section, then the projected use of the new substance is lower, on an ODP-weighted basis, than the baseline usage of the replaced ODS.

(33) [Reserved]

* * * * *

(39) *Pollution prevention* means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal; it does not mean recycling (other than certain ''in-process recycling'' practices), energy recovery, treatment, or disposal.

(40) *Significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

(41)(i) *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

(ii) In determining the projected actual emissions under paragraph (b)(41)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:

(*a*) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan; and

(*b*) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions; and

(*c*) Shall exclude, in calculating any increase in emissions that results from he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or

(*d*) In lieu of using the method set out in paragraphs (a)(41)(ii)(a) through (c) of this section, may elect to use the emissions unit's potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.

(42) *Clean Unit* means any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to paragraph (x) of this section; or any emissions unit that has been designated by the Administrator as a Clean Unit, based on the criteria in paragraphs (y)(3)(i) through (iv) of this section; or any emissions unit that has been issued a major NSR permit that requires compliance with BACT or LAER, is complying with such BACT/LAER requirements, and qualifies as a Clean Unit pursuant to regulations approved into the State Implementation Plan in accordance with § 51.165(c) or § 51.166(u) of this chapter; or any emissions unit that has been designated by the reviewing authority as a Clean Unit in accordance with regulations approved into the plan to carry out § 51.165(d) or § 51.166(u) of this chapter.

(43) *Prevention of Significant Deterioration (PSD) program* means the EPA-implemented major source preconstruction permit programs under this section or a major source preconstruction permit program that has been approved by the Administrator and incorporated into the State Implementation Plan pursuant to § 51.166 of this chapter to implement the requirements of that section. Any permit issued under such a program is a major NSR permit.

(44) *Continuous emissions monitoring system (CEMS)* means all of the equipment that may be required to meet the data acquisition and availability requirements of this section, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

(45) *Predictive emissions monitoring system (PEMS)* means all of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

(46) *Continuous parameter monitoring system (CPMS)* means all of the equipment necessary to meet the data acquisition and availability requirements of this section, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O_2 or CO_2 concentrations), and to record average operational parameter value(s) on a continuous basis.

(47) *Continuous emissions rate monitoring system (CERMS)* means the total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

(48) *Baseline actual emissions* means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section.

(i) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*d*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraph (b)(48)(i)(*b*) of this section.

(ii) For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

(*a*) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

(*b*) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive 24-month period.

(*c*) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitations during the consecutive 24-month period. However, if an emission limitation is part of a maximum achievable control technology standard that the Administrator proposed or promulgated under part 63 of this chapter, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan consistent with the requirements of § 51.165(a)(3)(ii)(G) of this chapter.

(*d*) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for all the emissions units being changed. A different consecutive 24-month period can be used For each regulated NSR pollutant.

(*e*) The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by paragraphs (b)(48)(ii)(*b*) and (*c*) of this section.

(iii) For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

(iv) For a PAL for a stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in paragraph (b)(48)(i) of this section, for other existing emissions units in accordance with the procedures contained in paragraph (b)(48)(ii) of this section, and for a new emissions unit in accordance with the procedures contained in paragraph (b)(48)(iii) of this section.

(49) [Reserved]

(50) *Regulated NSR pollutant,* for purposes of this section, means the following:

(i) Any pollutant for which a national ambient air quality standard has been promulgated and any constituents or precursors for such pollutants identified by the Administrator (*e.g.*, volatile organic compounds are precursors for ozone);

(ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;

(iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(iv) Any pollutant that otherwise is subject to regulation under the Act; except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not been delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

(51) *Reviewing authority* means the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to carry out a permit program under § 51.165 and § 51.166 of this chapter, or the Administrator in the case of EPA-implemented permit programs under this section.

(52) *Project* means a physical change in, or change in the method of operation of, an existing major stationary source.

(53) *Lowest achievable emission rate (LAER)* is as defined in § 51.165(a)(1)(xiii) of this chapter.

(54) *Reasonably available control technology (RACT)* is as defined in § 51.100(o) of this chapter.

* * * * *

(i) Exemptions. * * *

* * * * *

(r) * * *

(5) [Reserved]

(6) The provisions of this paragraph (r)(6) apply to projects at an existing emissions unit at a major stationary source (other than projects at a Clean Unit or at a source with a PAL) in circumstances where there is a reasonable possibility that a project that is not a part of a major modification may result in a significant emissions increase and the owner or operator elects to use the method specified in paragraphs (b)(41)(ii)(*a*) through (*c*) of this section for calculating projected actual emissions.

(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(*a*) A description of the project;

(*b*) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(*c*) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under paragraph (b)(41)(ii)(*c*) of this section and an explanation for why such amount was excluded, and any netting calculations, if applicable.

(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in paragraph (r)(6)(i) of this section to the Administrator. Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction.

(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(*b*) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated NSR pollutant at such emissions unit.

(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Administrator within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report.

(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Administrator if the annual emissions, in tons per year, from the project identified in paragraph (r)(6)(i) of this section, exceed the baseline actual emissions (as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section), by a significant amount (as defined in paragraph (b)(23) of this section) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to paragraph (r)(6)(i)(*c*) of this section. Such report shall be submitted to the Administrator within 60 days after the end of such year. The report shall contain the following:

(*a*) The name, address and telephone number of the major stationary source;

(*b*) The annual emissions as calculated pursuant to paragraph (r)(6)(iii) of this section; and

(*c*) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

(7) The owner or operator of the source shall make the information required to be documented and maintained pursuant to paragraph (r)(6) of this section available for review upon a request for inspection by the Administrator or the general public pursuant to the requirements contained in § 70.4(b)(3)(viii) of this chapter.

* * * * *

(x) *Clean Unit Test for emissions units that are subject to BACT or LAER.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (x)(1) through (9) of this section.

(1) *Applicability.* The provisions of this paragraph (x) apply to any emissions unit for which a reviewing authority has issued a major NSR permit within the last 10 years.

(2) *General provisions for Clean Units.* The provisions in paragraphs (x)(2)(i) through (iv) of this section apply to a Clean Unit.

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (x)(4) of this section) and before the expiration date (as determined in accordance with paragraph (x)(5) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT and the project would not alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that were adopted in conjunction with BACT or the project would alter any physical or operational characteristics that formed the basis for the BACT determination as specified in paragraph (x)(6)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (x)(3)(iii) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit Applicability Test.* An emissions unit automatically qualifies

as a Clean Unit when the unit meets the criteria in paragraphs (x)(3)(i) and (ii) of this section. After the original Clean Unit expires in accordance with paragraph (x)(5) of this section or is lost pursuant to paragraph (x)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (x)(3)(iii) of this section, or under the Clean Unit provisions in paragraph (y) of this section. To re-qualify as a Clean Unit under paragraph (x)(3)(iii) of this section, the emissions unit must obtain a new major NSR permit issued through the applicable PSD program and meet all the criteria in paragraph (x)(3)(iii) of this section. The Clean Unit designation applies individually for each pollutant emitted by the emissions unit.

(i) *Permitting requirement.* The emissions unit must have received a major NSR permit within the last 10 years. The owner or operator must maintain and be able to provide information that would demonstrate that this permitting requirement is met.

(ii) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (x)(3)(ii)(*a*) and (*b*) of this section.

(*a*) The control technology achieves the BACT or LAER level of emissions reductions as determined through issuance of a major NSR permit within the past 10 years. However, the emissions unit is not eligible for the Clean Unit designation if the BACT determination resulted in no requirement to reduce emissions below the level of a standard, uncontrolled, new emissions unit of the same type.

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or expenses to apply a pollution prevention technique to an emissions unit.

(iii) *Re-qualifying for the Clean Unit designation.* The emissions unit must obtain a new major NSR permit that requires compliance with the current-day BACT (or LAER), and the emissions unit must meet the requirements in paragraphs (x)(3)(i) and (x)(3)(ii) of this section.

(4) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project at the emissions unit is a major modification) is determined according to the applicable paragraph (x)(4)(i) or (x)(4)(ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify as Clean Units by implementing new control technology to meet current-day BACT.* The effective date is the date the emissions unit's air pollution control technology is placed into service, or 3 years after the issuance date of the major NSR permit, whichever is earlier, but no sooner than March 3, 2003, that is the date these provisions become effective.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* The effective date is the date the new, major NSR permit is issued.

(5) *Clean Unit expiration.* An emissions unit's Clean Unit designation expires (that is, the date on which the owner or operator may no longer use the Clean Unit Test to determine whether a project affecting the emissions unit is, or is part of, a major modification) according to the applicable paragraph (x)(5)(i) or (ii) of this section.

(i) *Original Clean Unit designation, and emissions units that re-qualify by implementing new control technology to meet current-day BACT.* For any emissions unit that automatically qualifies as a Clean Unit under paragraphs (x)(3)(i) and (ii) of this section or re-qualifies by implementing new control technology to meet current-day BACT under paragraph (x)(3)(iii) of this section, the Clean Unit designation expires 10 years after the effective date, or the date the equipment went into service, whichever is earlier; or, it expires at any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(ii) *Emissions units that re-qualify for the Clean Unit designation using an existing control technology.* For any emissions unit that re-qualifies as a Clean Unit under paragraph (x)(3)(iii) of this section using an existing control technology, the Clean Unit designation expires 10 years after the effective date; or, it expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (x)(7) of this section.

(6) *Required title V permit content for a Clean Unit.* After the effective date of the Clean Unit designation, and in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed, the title V permit for the major stationary source must include the following terms and conditions in paragraphs (x)(6)(i) through (vi) of this section related to the Clean Unit.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded in the title V permit (*e.g.,* because the air pollution control technology is not yet in service), the permit must describe the event that will determine the effective date (*e.g.,* the date the control technology is placed into service). Once the effective date is determined, the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) *The expiration date of the Clean Unit designation.* If this date is not known when the Clean Unit designation is initially recorded into the title V permit (*e.g.,* because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.,* the date the control technology is placed into service). Once the expiration date is determined, the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with BACT, and any physical or operational characteristics which formed the basis for the BACT determination (*e.g.,* possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining the Clean Unit designation. (See paragraph (x)(7) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (x)(7) of this section.

(7) *Maintaining the Clean Unit designation.* To maintain the Clean Unit

designation, the owner or operator must conform to all the restrictions listed in paragraphs (x)(7)(i) through (iii) of this section. This paragraph (x)(7) applies independently to each pollutant for which the emissions unit has the Clean Unit designation. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted in conjunction with the BACT that is recorded in the major NSR permit, and subsequently reflected in the title V permit. The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the BACT determination (*e.g.,* possibly the emissions unit's capacity or throughput).

(ii) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(iii) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(8) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a "netting analysis"), unless such use occurs before the effective date of the Clean Unit designation, or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(9) *Effect of redesignation on the Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by re-designation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if an existing Clean Unit designation expires, it must re-qualify under the requirements that are currently applicable in the area.

(y) *Clean Unit provisions for emissions units that achieve an emission limitation comparable to BACT.* An owner or operator of a major stationary source has the option of using the Clean Unit Test to determine whether emissions increases at a Clean Unit are part of a project that is a major modification according to the provisions in paragraphs (y)(1) through (11) of this section.

(1) *Applicability.* The provisions of this paragraph (y) apply to emissions units which do not qualify as Clean Units under paragraph (x) of this section, but which are achieving a level of emissions control comparable to BACT, as determined by the Administrator in accordance with this paragraph (y).

(2) *General provisions for Clean Units.* The provisions in paragraphs (y)(2)(i) through (iv) of this section apply to a Clean Unit (designated under this paragraph (y)).

(i) Any project for which the owner or operator begins actual construction after the effective date of the Clean Unit designation (as determined in accordance with paragraph (y)(5) of this section) and before the expiration date (as determined in accordance with paragraph (y)(6) of this section) will be considered to have occurred while the emissions unit was a Clean Unit.

(ii) If a project at a Clean Unit does not cause the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, and the project would not alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, the emissions unit remains a Clean Unit.

(iii) If a project causes the need for a change in the emission limitations or work practice requirements in the permit for the unit that have been determined (pursuant to paragraph (y)(4) of this section) to be comparable to BACT, or the project would alter any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT as specified in paragraph (y)(8)(iv) of this section, then the emissions unit loses its designation as a Clean Unit upon issuance of the necessary permit revisions (unless the unit re-qualifies as a Clean Unit pursuant to paragraph (u)(3)(iv) of this section). If the owner or operator begins actual construction on the project without first applying to revise the emissions unit's permit, the Clean Unit designation ends immediately prior to the time when actual construction begins.

(iv) A project that causes an emissions unit to lose its designation as a Clean Unit is subject to the applicability requirements of paragraphs (a)(2)(iv)(*a*) through (*d*) and paragraph (a)(2)(iv)(*f*) of this section as if the emissions unit is not a Clean Unit.

(3) *Qualifying or re-qualifying to use the Clean Unit applicability test.* An emissions unit qualifies as a Clean Unit when the unit meets the criteria in paragraphs (y)(3)(i) through (iii) of this section. After the original Clean Unit designation expires in accordance with paragraph (y)(6) of this section or is lost pursuant to paragraph (y)(2)(iii) of this section, such emissions unit may re-qualify as a Clean Unit under either paragraph (y)(3)(iv) of this section, or under the Clean Unit provisions in paragraph (x) of this section. To re-qualify as a Clean Unit under paragraph (y)(3)(iv) of this section, the emissions unit must obtain a new permit issued pursuant to the requirements in paragraphs (y)(7) and (8) of this section and meet all the criteria in paragraph (y)(3)(iv) of this section. The Administrator will make a separate Clean Unit designation for each pollutant emitted by the emissions unit for which the emissions unit qualifies as a Clean Unit.

(i) *Qualifying air pollution control technologies.* Air pollutant emissions from the emissions unit must be reduced through the use of air pollution control technology (which includes pollution prevention as defined under paragraph (b)(39) of this section or work practices) that meets both the following requirements in paragraphs (y)(3)(i)(*a*) and (*b*) of this section.

(*a*) The owner or operator has demonstrated that the emissions unit's control technology is comparable to BACT according to the requirements of paragraph (y)(4) of this section. However, the emissions unit is not eligible for a Clean Unit designation if its emissions are not reduced below the level of a standard, uncontrolled emissions unit of the same type (*e.g.,* if the BACT determinations to which it is compared have resulted in a determination that no control measures are required).

(*b*) The owner or operator made an investment to install the control technology. For the purpose of this determination, an investment includes expenses to research the application of a pollution prevention technique to the emissions unit or to retool the unit to apply a pollution prevention technique.

(ii) *Impact of emissions from the unit.* The Administrator must determine that the allowable emissions from the emissions unit will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(iii) *Date of installation.* An emissions unit may qualify as a Clean Unit even if the control technology, on which the Clean Unit designation is based, was installed before March 3, 2003. However, for such emissions units, the owner or operator must apply for the Clean Unit designation before December 31, 2004. For technologies installed on and after March 3, 2003, the owner or operator must apply for the Clean Unit designation at the time the control technology is installed.

(iv) *Re-qualifying as a Clean Unit.* The emissions unit must obtain a new permit (pursuant to requirements in paragraphs (y)(7) and (8) of this section) that demonstrates that the emissions unit's control technology is achieving a level of emission control comparable to current-day BACT, and the emissions unit must meet the requirements in paragraphs (y)(3)(i)(a) and (y)(3)(ii) of this section.

(4) *Demonstrating control effectiveness comparable to BACT.* The owner or operator may demonstrate that the emissions unit's control technology is comparable to BACT for purposes of paragraph (y)(3)(i) of this section according to either paragraph (y)(4)(i) or (ii) of this section. Paragraph (y)(4)(iii) of this section specifies the time for making this comparison.

(i) *Comparison to previous BACT and LAER determinations.* The Administrator maintains an on-line data base of previous determinations of RACT, BACT, and LAER in the RACT/BACT/LAER Clearinghouse (RBLC). The emissions unit's control technology is presumed to be comparable to BACT if it achieves an emission limitation that is equal to or better than the average of the emission limitations achieved by all the sources for which a BACT or LAER determination has been made within the preceding 5 years and entered into the RBLC, and for which it is technically feasible to apply the BACT or LAER control technology to the emissions unit. The Administrator shall also compare this presumption to any additional BACT or LAER determinations of which he or she is aware, and shall consider any information on achieved-in-practice pollution control technologies provided during the public comment period, to determine whether any presumptive determination that the control technology is comparable to BACT is correct.

(ii) *The substantially-as-effective test.* The owner or operator may demonstrate that the emissions unit's control technology is substantially as effective as BACT. In addition, any other person may present evidence related to whether the control technology is substantially as effective as BACT during the public participation process required under paragraph (y)(7) of this section. The Administrator shall consider such evidence on a case-by-case basis and determine whether the emissions unit's air pollution control technology is substantially as effective as BACT.

(iii) *Time of comparison.*

(*a*) *Emissions units with control technologies that are installed before March 3, 2003.* The owner or operator of an emissions unit whose control technology is installed before March 3, 2003 may, at its option, either demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, or demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements. The expiration date of the Clean Unit designation will depend on which option the owner or operator uses, as specified in paragraph (y)(6) of this section.

(*b*) *Emissions units with control technologies that are installed on and after March 3, 2003.* The owner or operator must demonstrate that the emission limitation achieved by the emissions unit's control technology is comparable to current-day BACT requirements.

(5) *Effective date of the Clean Unit designation.* The effective date of an emissions unit's Clean Unit designation (that is, the date on which the owner or operator may begin to use the Clean Unit Test to determine whether a project involving the emissions unit is a major modification) is the date that the permit required by paragraph (y)(7) of this section is issued or the date that the emissions unit's air pollution control technology is placed into service, whichever is later.

(6) *Clean Unit expiration.* If the owner or operator demonstrates that the emission limitation achieved by the emissions unit's control technology is comparable to the BACT requirements that applied at the time the control technology was installed, then the Clean Unit designation expires 10 years from the date that the control technology was installed. For all other emissions units, the Clean Unit designation expires 10 years from the effective date of the Clean Unit designation, as determined according to paragraph (y)(5) of this section. In addition, for all emissions units, the Clean Unit designation expires any time the owner or operator fails to comply with the provisions for maintaining the Clean Unit designation in paragraph (y)(9) of this section.

(7) *Procedures for designating emissions units as Clean Units.* The Administrator shall designate an emissions unit a Clean Unit only by issuing a permit through a permitting program that has been approved by the Administrator and that conforms with the requirements of §§ 51.160 through 51.164 of this chapter including requirements for public notice of the proposed Clean Unit designation and opportunity for public comment. Such permit must also meet the requirements in paragraph (y)(8) of this section.

(8) *Required permit content.* The permit required by paragraph (y)(7) of this section shall include the terms and conditions set forth in paragraphs (y)(8)(i) through (vi) of this section. Such terms and conditions shall be incorporated into the major stationary source's title V permit in accordance with the provisions of the applicable title V permit program under part 70 or part 71 of this chapter, but no later than when the title V permit is renewed.

(i) A statement indicating that the emissions unit qualifies as a Clean Unit and identifying the pollutant(s) for which this designation applies.

(ii) *The effective date of the Clean Unit designation.* If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the effective date (*e.g.*, the date the control technology is placed into service). Once the effective date is known, then the owner or operator must notify the Administrator of the exact date. This specific effective date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iii) The expiration date of the Clean Unit designation. If this date is not known when the Administrator issues the permit (*e.g.*, because the air pollution control technology is not yet in service), then the permit must describe the event that will determine the expiration date (*e.g.*, the date the control technology is placed into service). Once the expiration date is known, then the owner or operator must notify the Administrator of the exact date. The expiration date must be added to the source's title V permit at the first opportunity, such as a modification, revision, reopening, or renewal of the title V permit for any reason, whichever comes first, but in no case later than the next renewal.

(iv) All emission limitations and work practice requirements adopted in conjunction with emission limitations necessary to assure that the control technology continues to achieve an emission limitation comparable to BACT, and any physical or operational characteristics that formed the basis for determining that the emissions unit's control technology achieves a level of emissions control comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(v) Monitoring, recordkeeping, and reporting requirements as necessary to demonstrate that the emissions unit continues to meet the criteria for maintaining its Clean Unit designation. (See paragraph (y)(9) of this section.)

(vi) Terms reflecting the owner or operator's duties to maintain the Clean Unit designation and the consequences of failing to do so, as presented in paragraph (y)(9) of this section.

(9) *Maintaining a Clean Unit designation.* To maintain the Clean Unit designation, the owner or operator must conform to all the restrictions listed in paragraphs (y)(9)(i) through (v) of this section. This paragraph (y)(9) applies independently to each pollutant for which the Administrator has designated the emissions unit a Clean Unit. That is, failing to conform to the restrictions for one pollutant affects the Clean Unit designation only for that pollutant.

(i) The Clean Unit must comply with the emission limitation(s) and/or work practice requirements adopted to ensure that the control technology continues to achieve emission control comparable to BACT.

(ii) The owner or operator may not make a physical change in or change in the method of operation of the Clean Unit that causes the emissions unit to function in a manner that is inconsistent with the physical or operational characteristics that formed the basis for the determination that the control technology is achieving a level of emission control that is comparable to BACT (*e.g.*, possibly the emissions unit's capacity or throughput).

(iii) [Reserved]

(iv) The Clean Unit must comply with any terms and conditions in the title V permit related to the unit's Clean Unit designation.

(v) The Clean Unit must continue to control emissions using the specific air pollution control technology that was the basis for its Clean Unit designation. If the emissions unit or control technology is replaced, then the Clean Unit designation ends.

(10) *Netting at Clean Units.* Emissions changes that occur at a Clean Unit must not be included in calculating a significant net emissions increase (that is, must not be used in a ''netting analysis'') unless such use occurs before March 3, 2003 or after the Clean Unit designation expires; or, unless the emissions unit reduces emissions below the level that qualified the unit as a Clean Unit. However, if the Clean Unit reduces emissions below the level that qualified the unit as a Clean Unit, then the owner or operator may generate a credit for the difference between the level that qualified the unit as a Clean Unit and the emissions unit's new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(11) *Effect of redesignation on a Clean Unit designation.* The Clean Unit designation of an emissions unit is not affected by redesignation of the attainment status of the area in which it is located. That is, if a Clean Unit is located in an attainment area and the area is redesignated to nonattainment, its Clean Unit designation is not affected. Similarly, redesignation from nonattainment to attainment does not affect the Clean Unit designation. However, if a Clean Unit's designation expires or is lost pursuant to paragraphs (x)(2)(iii) and (y)(2)(iii) of this section, it must re-qualify under the requirements that are currently applicable.

(z) *PCP exclusion procedural requirements.* PCPs shall be provided according to the provisions in paragraphs (z)(1) through (6) of this section.

(1) Before an owner or operator begins actual construction of a PCP, the owner or operator must either submit a notice to the Administrator if the project is listed in paragraphs (b)(32)(i) through (vi) of this section, or if the project is not listed in paragraphs (b)(32)(i) through (vi) of this section, then the owner or operator must submit a permit application and obtain approval to use the PCP exclusion from the Administrator consistent with the requirements in paragraph (z)(5) of this section. Regardless of whether the owner or operator submits a notice or a permit application, the project must meet the requirements in paragraph (z)(2) of this section, and the notice or permit application must contain the information required in paragraph (z)(3) of this section.

(2) Any project that relies on the PCP exclusion must meet the requirements of paragraphs (z)(2)(i) and (ii) of this section.

(i) *Environmentally beneficial analysis.* The environmental benefit from the emissions reductions of pollutants regulated under the Act must outweigh the environmental detriment of emissions increases in pollutants regulated under the Act. A statement that a technology from paragraphs (b)(32)(i) through (vi) of this section is being used shall be presumed to satisfy this requirement.

(ii) *Air quality analysis.* The emissions increases from the project will not cause or contribute to a violation of any national ambient air quality standard or PSD increment, or adversely impact an air quality related value (such as visibility) that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(3) *Content of notice or permit application.* In the notice or permit application sent to the Administrator, the owner or operator must include, at a minimum, the information listed in paragraphs (z)(3)(i) through (v) of this section.

(i) A description of the project.

(ii) The potential emissions increases and decreases of any pollutant regulated under the Act and the projected emissions increases and decreases using the methodology in paragraph (a)(2)(iv) of this section, that will result from the project, and a copy of the environmentally beneficial analysis required by paragraph (z)(2)(i) of this section.

(iii) A description of monitoring and recordkeeping, and all other methods, to be used on an ongoing basis to demonstrate that the project is environmentally beneficial. Methods should be sufficient to meet the requirements in part 70 and part 71 of this chapter.

(iv) A certification that the project will be designed and operated in a manner that is consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(v) Demonstration that the PCP will not have an adverse air quality impact (*e.g.*, modeling, screening level modeling results, or a statement that the collateral emissions increase is included within the parameters used in the most recent modeling exercise) as required by paragraph (z)(2)(ii) of this section. An air quality impact analysis is not required for any pollutant that will not experience a significant emissions increase as a result of the project.

(4) *Notice process for listed projects.* For projects listed in paragraphs (b)(32)(i) through (vi) of this section, the owner or operator may begin actual construction of the project immediately after notice is sent to the Administrator (unless otherwise prohibited under requirements of the applicable State Implementation Plan). The owner or operator shall respond to any requests by the Administrator for additional information that the Administrator determines is necessary to evaluate the suitability of the project for the PCP exclusion.

(5) *Permit process for unlisted projects.* Before an owner or operator may begin actual construction of a PCP project that is not listed in paragraphs (b)(32)(i) through (vi) of this section, the project must be approved by the Administrator and recorded in a State Implementation Plan-approved permit or title V permit using procedures that are consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval, with access to the environmentally beneficial analysis and the air quality analysis, and provide at least a 30-day period for the public and the Administrator to submit comments. The Administrator must address all material comments received by the end of the comment period before taking final action on the permit.

(6) *Operational requirements.* Upon installation of the PCP, the owner or operator must comply with the requirements of paragraphs (z)(6)(i) through (iv) of this section.

(i) *General duty.* The owner or operator must operate the PCP in a manner consistent with proper industry and engineering practices, in a manner that is consistent with the environmentally beneficial analysis and air quality analysis required by paragraphs (z)(2)(i) and (ii) of this section, with information submitted in the notice or permit application required by paragraph (z)(3) of this section, and in such a way as to minimize, within the physical configuration and operational standards usually associated with the emissions control device or strategy, emissions of collateral pollutants.

(ii) *Recordkeeping.* The owner or operator must maintain copies on site of the environmentally beneficial analysis, the air quality impacts analysis, and monitoring and other emission records to prove that the PCP operated consistent with the general duty requirements in paragraph (z)(6)(i) of this section.

(iii) *Permit requirements.* The owner or operator must comply with any provisions in the State Implementation Plan-approved permit or title V permit related to use and approval of the PCP exclusion.

(iv) *Generation of emission reduction credits.* Emission reductions created by a PCP shall not be included in calculating a significant net emissions increase unless the emissions unit further reduces emissions after qualifying for the PCP exclusion (*e.g.*, taking an operational restriction on the hours of operation). The owner or operator may generate a credit for the difference between the level of reduction which was used to qualify for the PCP exclusion and the new emissions limit if such reductions are surplus, quantifiable, and permanent. For purposes of generating offsets, the reductions must also be federally enforceable. For purposes of determining creditable net emissions increases and decreases, the reductions must also be enforceable as a practical matter.

(aa) *Actuals PALs.* The provisions in paragraphs (aa)(1) through (15) of this section govern actuals PALs.

(1) *Applicability.*

(i) The Administrator may approve the use of an actuals PAL for any existing major stationary source if the PAL meets the requirements in paragraphs (aa)(1) through (15) of this section. The term ''PAL'' shall mean ''actuals PAL'' throughout paragraph (aa) of this section.

(ii) Any physical change in or change in the method of operation of a major stationary source that maintains its total source-wide emissions below the PAL level, meets the requirements in paragraphs (aa)(1) through (15) of this section, and complies with the PAL permit:

(*a*) Is not a major modification for the PAL pollutant;

(*b*) Does not have to be approved through the PSD program; and

(*c*) Is not subject to the provisions in paragraph (r)(4) of this section (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program).

(iii) Except as provided under paragraph (aa)(1)(ii)(*c*) of this section, a major stationary source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

(2) *Definitions.* For the purposes of this section, the definitions in paragraphs (aa)(2)(i) through (xi) of this section apply. When a term is not defined in these paragraphs, it shall have the meaning given in paragraph (b) of this section or in the Act.

(i) *Actuals PAL* for a major stationary source means a PAL based on the baseline actual emissions (as defined in paragraph (b)(48) of this section) of all emissions units (as defined in paragraph (b)(7) of this section) at the source, that emit or have the potential to emit the PAL pollutant.

(ii) *Allowable emissions* means ''allowable emissions'' as defined in paragraph (b)(16) of this section, except as this definition is modified according to paragraphs (aa)(2)(ii)(*a*) and (*b*) of this section.

(*a*) The allowable emissions for any emissions unit shall be calculated considering any emission limitations that are enforceable as a practical matter on the emissions unit's potential to emit.

(*b*) An emissions unit's potential to emit shall be determined using the definition in paragraph (b)(4) of this section, except that the words ''or enforceable as a practical matter'' should be added after ''federally enforceable.''

(iii) *Small emissions unit* means an emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant, as defined in paragraph (b)(23) of this section or in the Act, whichever is lower.

(iv) *Major emissions unit* means:

(*a*) Any emissions unit that emits or has the potential to emit 100 tons per year or more of the PAL pollutant in an attainment area; or

(*b*) Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major source threshold for the PAL pollutant as defined by the Act for nonattainment areas. For example, in accordance with the definition of major stationary source in section 182(c) of the Act, an emissions unit would be a major emissions unit for VOC if the emissions unit is located in a serious ozone nonattainment area and it emits or has the potential to emit 50 or more tons of VOC per year.

(v) *Plantwide applicability limitation (PAL)* means an emission limitation expressed in tons per year, for a pollutant at a major stationary source, that is enforceable as a practical matter and established source-wide in accordance with paragraphs (aa)(1) through (15) of this section.

(vi) *PAL effective date* generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(vii) *PAL effective period* means the period beginning with the PAL effective date and ending 10 years later.

(viii) *PAL major modification* means, notwithstanding paragraphs (b)(2) and (b)(3) of this section (the definitions for major modification and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

(ix) *PAL permit* means the major NSR permit, the minor NSR permit, or the State operating permit under a program that is approved into the State Implementation Plan, or the title V permit issued by the Administrator that establishes a PAL for a major stationary source.

(x) *PAL pollutant* means the pollutant for which a PAL is established at a major stationary source.

(xi) *Significant emissions unit* means an emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in paragraph (b)(23) of this section or in the Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit as defined in paragraph (aa)(2)(iv) of this section.

(3) *Permit application requirements.* As part of a permit application requesting a PAL, the owner or operator of a major stationary source shall submit the following information to the Administrator for approval:

(i) A list of all emissions units at the source designated as small, significant or major based on their potential to emit. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations, or work practices apply to each unit.

(ii) Calculations of the baseline actual emissions (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown, and malfunction.

(iii) The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total for each month as required by paragraph (aa)(13)(i) of this section.

(4) *General requirements for establishing PALs.*

(i) The Administrator is allowed to establish a PAL at a major stationary source, provided that at a minimum, the requirements in paragraphs (aa)(4)(i)(a) through (g) of this section are met.

(*a*) The PAL shall impose an annual emission limitation in tons per year, that is enforceable as a practical matter, for the entire major stationary source. For each month during the PAL effective period after the first 12 months of establishing a PAL, the major stationary source owner or operator shall show that the sum of the monthly emissions from each emissions unit under the PAL for the previous 12 consecutive months is less than the PAL (a 12-month average, rolled monthly). For each month during the first 11 months from the PAL effective date, the major stationary source owner or operator shall show that the sum of the preceding monthly emissions from the PAL effective date for each emissions unit under the PAL is less than the PAL.

(*b*) The PAL shall be established in a PAL permit that meets the public participation requirements in paragraph (aa)(5) of this section.

(*c*) The PAL permit shall contain all the requirements of paragraph (aa)(7) of this section.

(*d*) The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source.

(*e*) Each PAL shall regulate emissions of only one pollutant.

(*f*) Each PAL shall have a PAL effective period of 10 years.

(*g*) The owner or operator of the major stationary source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in paragraphs (aa)(12) through (14) of this section for each emissions unit under the PAL through the PAL effective period.

(ii) At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant that occur during the PAL effective period creditable as decreases for purposes of offsets under § 51.165(a)(3)(ii) of this chapter unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

(5) *Public participation requirements for PALs.* PALs for existing major stationary sources shall be established, renewed, or increased through a procedure that is consistent with §§ 51.160 and 51.161 of this chapter. This includes the requirement that the Administrator provide the public with notice of the proposed approval of a PAL permit and at least a 30-day period for submittal of public comment. The Administrator must address all material comments before taking final action on the permit.

(6) *Setting the 10-year actuals PAL level.* The actuals PAL level for a major stationary source shall be established as the sum of the baseline actual emissions (as defined in paragraph (b)(48) of this section) of the PAL pollutant for each emissions unit at the source; plus an amount equal to the applicable significant level for the PAL pollutant under paragraph (b)(23) of this section or under the Act, whichever is lower. When establishing the actuals PAL level, for a PAL pollutant, only one consecutive 24-month period must be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive 24-month period may be used for each different PAL pollutant. Emissions associated with units that were permanently shutdown after this 24-month period must be subtracted from the PAL level. Emissions from units on which actual construction began after the 24-month period must be added to the PAL level in an amount equal to the potential to emit of the units. The Administrator shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future

compliance date(s) of any applicable Federal or State regulatory requirement(s) that the Administrator is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NO_X to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

(7) *Contents of the PAL permit.* The PAL permit must contain, at a minimum, the information in paragraphs (aa)(7)(i) through (x) of this section.

(i) The PAL pollutant and the applicable source-wide emission limitation in tons per year.

(ii) The PAL permit effective date and the expiration date of the PAL (PAL effective period).

(iii) Specification in the PAL permit that if a major stationary source owner or operator applies to renew a PAL in accordance with paragraph (aa)(10) of this section before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by a reviewing authority.

(iv) A requirement that emission calculations for compliance purposes must include emissions from startups, shutdowns, and malfunctions.

(v) A requirement that, once the PAL expires, the major stationary source is subject to the requirements of paragraph (aa)(9) of this section.

(vi) The calculation procedures that the major stationary source owner or operator shall use to convert the monitoring system data to monthly emissions and annual emissions based on a 12-month rolling total as required by paragraph (aa)(13)(i) of this section.

(vii) A requirement that the major stationary source owner or operator monitor all emissions units in accordance with the provisions under paragraph (aa)(12) of this section.

(viii) A requirement to retain the records required under paragraph (aa)(13) of this section on site. Such records may be retained in an electronic format.

(ix) A requirement to submit the reports required under paragraph (aa)(14) of this section by the required deadlines.

(x) Any other requirements that the Administrator deems necessary to implement and enforce the PAL.

(8) *PAL effective period and reopening of the PAL permit.* The requirements in paragraphs (aa)(8)(i) and (ii) of this section apply to actuals PALs.

(i) *PAL effective period.* The Administrator shall specify a PAL effective period of 10 years.

(ii) *Reopening of the PAL permit.*

(*a*) During the PAL effective period, the Administrator must reopen the PAL permit to:

(*1*) Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL;

(*2*) Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under § 51.165(a)(3)(ii) of this chapter; and

(*3*) Revise the PAL to reflect an increase in the PAL as provided under paragraph (aa)(11) of this section.

(*b*) The Administrator shall have discretion to reopen the PAL permit for the following:

(*1*) Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date;

(*2*) Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the State may impose on the major stationary source under the State Implementation Plan; and

(*3*) Reduce the PAL if the reviewing authority determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

(*c*) Except for the permit reopening in paragraph (aa)(8)(ii)(*a*)(*1*) of this section for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of paragraph (aa)(5) of this section.

(9) *Expiration of a PAL.* Any PAL that is not renewed in accordance with the procedures in paragraph (aa)(10) of this section shall expire at the end of the PAL effective period, and the requirements in paragraphs (aa)(9)(i) through (v) of this section shall apply.

(i) Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in paragraphs (aa)(9)(i)(*a*) and (*b*) of this section.

(*a*) Within the time frame specified for PAL renewals in paragraph (aa)(10)(ii) of this section, the major stationary source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as decided by the Administrator) by distributing the PAL allowable emissions for the major stationary source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under paragraph (aa)(10)(v) of this section, such distribution shall be made as if the PAL had been adjusted.

(*b*) The Administrator shall decide whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Administrator determines is appropriate.

(ii) Each emissions unit(s) shall comply with the allowable emission limitation on a 12-month rolling basis. The Administrator may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS, or CPMS to demonstrate compliance with the allowable emission limitation.

(iii) Until the Administrator issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under paragraph (aa)(9)(i)(*b*) of this section, the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

(iv) Any physical change or change in the method of operation at the major stationary source will be subject to major NSR requirements if such change meets the definition of major modification in paragraph (b)(2) of this section.

(v) The major stationary source owner or operator shall continue to comply with any State or Federal applicable requirements (BACT, RACT, NSPS, etc.) that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to paragraph (r)(4) of this section, but were eliminated by the PAL in accordance with the provisions in paragraph (aa)(1)(ii)(*c*) of this section.

(10) *Renewal of a PAL.*

(i) The Administrator shall follow the procedures specified in paragraph (aa)(5) of this section in approving any request to renew a PAL for a major stationary source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the Administrator.

(ii) *Application deadline.* A major stationary source owner or operator shall submit a timely application to the Administrator to request renewal of a PAL. A timely application is one that is submitted at least 6 months prior to, but not earlier than 18 months from, the date of permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source submits a complete application to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

(iii) *Application requirements.* The application to renew a PAL permit shall contain the information required in paragraphs (aa)(10)(iii)(*a*) through (*d*) of this section.

(*a*) The information required in paragraphs (aa)(3)(i) through (iii) of this section.

(*b*) A proposed PAL level.

(*c*) The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

(*d*) Any other information the owner or operator wishes the Administrator to consider in determining the appropriate level for renewing the PAL.

(iv) *PAL adjustment.* In determining whether and how to adjust the PAL, the Administrator shall consider the options outlined in paragraphs (aa)(10)(iv)(*a*) and (*b*) of this section. However, in no case may any such adjustment fail to comply with paragraph (aa)(10)(iv)(*c*) of this section.

(*a*) If the emissions level calculated in accordance with paragraph (aa)(6) of this section is equal to or greater than 80 percent of the PAL level, the Administrator may renew the PAL at the same level without considering the factors set forth in paragraph (aa)(10)(iv)(*b*) of this section; or

(*b*) The Administrator may set the PAL at a level that he or she determines to be more representative of the source's baseline actual emissions, or that he or she determines to be more appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the Administrator in his or her written rationale.

(*c*) Notwithstanding paragraphs (aa)(10)(iv)(a) and (b) of this section:

(*1*) If the potential to emit of the major stationary source is less than the PAL, the Administrator shall adjust the PAL to a level no greater than the potential to emit of the source; and

(*2*) The Administrator shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source has complied with the provisions of paragraph (aa)(11) of this section (increasing a PAL).

(v) If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the Administrator has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or title V permit renewal, whichever occurs first.

(11) *Increasing a PAL during the PAL effective period.*

(i) The Administrator may increase a PAL emission limitation only if the major stationary source complies with the provisions in paragraphs (aa)(11)(i)(*a*) through (*d*) of this section.

(*a*) The owner or operator of the major stationary source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary source's emissions to equal or exceed its PAL.

(*b*) As part of this application, the major stationary source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding 10 years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

(*c*) The owner or operator obtains a major NSR permit for all emissions unit(s) identified in paragraph (aa)(11)(i)(*a*) of this section, regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT), even though they have also become subject to the PAL or continue to be subject to the PAL.

(*d*) The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

(ii) The Administrator shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with paragraph (aa)(11)(i)(*b*)), plus the sum of the baseline actual emissions of the small emissions units.

(iii) The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of paragraph (aa)(5) of this section.

(12) *Monitoring requirements for PALs.*

(i) General requirements.

(*a*) Each PAL permit must contain enforceable requirements for the monitoring system that accurately determines plantwide emissions of the PAL pollutant in terms of mass per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

(*b*) The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in paragraphs (aa)(12)(ii)(*a*) through (*d*) of this section and must be approved by the Administrator.

(*c*) Notwithstanding paragraph (aa)(12)(i)(*b*) of this section, you may also employ an alternative monitoring approach that meets paragraph (aa)(12)(i)(*a*) of this section if approved by the Administrator.

(*d*) Failure to use a monitoring system that meets the requirements of this section renders the PAL invalid.

(ii) Minimum performance requirements for approved monitoring approaches. The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in paragraphs (aa)(12)(iii) through (ix) of this section:

(*a*) Mass balance calculations for activities using coatings or solvents;

(*b*) CEMS;

(*c*) CPMS or PEMS; and

(*d*) Emission factors.

(iii) Mass balance calculations. An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

(*a*) Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

(*b*) Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

(*c*) Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the Administrator determines there is site-specific data or a site-specific monitoring program to support another content within the range.

(iv) CEMS. An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) CEMS must comply with applicable Performance Specifications found in 40 CFR part 60, appendix B; and

(*b*) CEMS must sample, analyze and record data at least every 15 minutes while the emissions unit is operating.

(v) CPMS or PEMS. An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) The CPMS or the PEMS must be based on current site-specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

(*b*) Each CPMS or PEMS must sample, analyze, and record data at least every 15 minutes, or at another less frequent interval approved by the Administrator, while the emissions unit is operating.

(vi) Emission factors. An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

(*a*) All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

(*b*) The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

(*c*) If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within 6 months of PAL permit issuance, unless the Administrator determines that testing is not required.

(vii) A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

(viii) Notwithstanding the requirements in paragraphs (aa)(12)(iii) through (vii) of this section, where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the Administrator shall, at the time of permit issuance:

(*a*) Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

(*b*) Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

(ix) Re-validation. All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the Administrator. Such testing must occur at least once every 5 years after issuance of the PAL.

(13) *Recordkeeping requirements.*

(i) The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of paragraph (aa) of this section and of the PAL, including a determination of each emissions unit's 12-month rolling total emissions, for 5 years from the date of such record.

(ii) The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus 5 years:

(*a*) A copy of the PAL permit application and any applications for revisions to the PAL; and

(*b*) Each annual certification of compliance pursuant to title V and the data relied on in certifying the compliance.

(14) *Reporting and notification requirements.* The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the Administrator in accordance with the applicable title V operating permit program. The reports shall meet the requirements in paragraphs (aa)(14)(i) through (iii) of this section.

(i) *Semi-annual report.* The semi-annual report shall be submitted to the Administrator within 30 days of the end of each reporting period. This report shall contain the information required in paragraphs (aa)(14)(i)(*a*) through (*g*) of this section.

(*a*) The identification of owner and operator and the permit number.

(*b*) Total annual emissions (tons/year) based on a 12-month rolling total for each month in the reporting period recorded pursuant to paragraph (aa)(13)(i) of this section.

(*c*) All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions.

(*d*) A list of any emissions units modified or added to the major stationary source during the preceding 6-month period.

(*e*) The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

(*f*) A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, and whether the emissions unit monitored by the monitoring system continued to operate, and the calculation of the emissions of the pollutant or the number determined by method included in the permit, as provided by (aa)(12)(vii).

(*g*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(ii) *Deviation report.* The major stationary source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to § 70.6(a)(3)(iii)(B) of this chapter shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by the applicable program implementing § 70.6(a)(3)(iii)(B) of this chapter. The reports shall contain the following information:

(*a*) The identification of owner and operator and the permit number;

(*b*) The PAL requirement that experienced the deviation or that was exceeded;

(*c*) Emissions resulting from the deviation or the exceedance; and

(*d*) A signed statement by the responsible official (as defined by the applicable title V operating permit program) certifying the truth, accuracy, and completeness of the information provided in the report.

(iii) *Re-validation results.* The owner or operator shall submit to the Administrator the results of any re-validation test or method within 3 months after completion of such test or method.

(15) *Transition requirements.*

(i) The Administrator may not issue a PAL that does not comply with the requirements in paragraphs (aa)(1) through (15) of this section after March 3, 2003.

(ii) The Administrator may supersede any PAL that was established prior to March 3, 2003 with a PAL that complies with the requirements of paragraphs (aa)(1) through (15) of this section.

(bb) If any provision of this section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

[FR Doc. 02–31899 Filed 12–30–02; 8:45 am]

BILLING CODE 6560–50–P

To: Johnson, Yvonne W[johnson.yvonnew@epa.gov]
From: Wood, Anna
Sent: Wed 10/4/2017 10:31:09 PM
Subject: CENSARA Slides
censara 2017 Fall _wTPs_oct 5.pptx

Hi, I cut a number of slides back to get to a more manageable amount. I will just speak to the priorities Mandy shared with us instead of having a slide on them and I will also just mention the lean stuff as well. I took out the PM 2.5 slides because there are not really any CENSARA states that have PM 2.5 NA areas in play. Can you please make sure the email from Vera on what we heard at AAPCA is in my background materials.

I also removed the transport slides for Pb, NO2 , SO2 and PM2.5 that you included at my request. I think I want to handle that a bit differently. I think Beth /someone in GSG has a list of the different NAAQS and the outstanding transport sips for the states for those NAAQS—can you please check on that for me. If that exists –it will have the info I need which is for the NAAQS (e.g., Pb, NO2, SO2,PM2.5) other than Ozone, which CENSARA states have outstanding transport SIP obligations. If we need to touch base on this tomorrow please just let me know.

Also for slide 9 re Round 2 SO2 NAAQS can I get a couple of talkers on the areas in TX and Ill. That we granted reconsideration for their SO2 Round 2 NA areas—Liz Etchells probably has this—there may also be something in my background materials on it. If there is something in my background materials I don't need anything from Liz.

I think you are asking GSG to update the talkers on the TX, LA and maybe AK RH SIPs-- thx

Last (I think) for the upcoming additional implementations tools/guidance for exceptional events on slide 13—do we have any sense of timing for these—I am thinking no but can you please ask Ben.

I am going to take one last look at the attached slides tonight and we can finalize everything in the morning and I should be in pretty good shape, thanks!!

Anna Marie Wood

Director, Air Quality Policy Division

OAQPS, U.S. EPA

109 T.W. Alexander Drive

Research Triangle Park, NC 27711

(919) 541-3604

To: Banister, Beverly[Banister.Beverly@epa.gov]
Cc: Johnson, Yvonne W[johnson.yvonnew@epa.gov]
From: Wood, Anna
Sent: Thur 6/1/2017 1:53:01 PM
Subject: RE: SESARM presentation
SESARM 2017 Spring Deck w_TPs.pptx

Hi--I am looking for things to cut out as it is too long as I only have one hour--maybe Lynorae /Heather will take some of it and handle--attached is the draft. If it would be easier to touch base and talk through it to parse out I am available at noon to discuss. If I can remove some of the slides I'd actually like to include a slide on the EOs and SIP back log status from a national perspective which was not on the list Lynorae gave to Yvonne but I think would be good to cover -- let me know what you would like to do --I can meet with Lynorae and Heather if they are available at noon. Thx

-----Original Message-----
From: Banister, Beverly
Sent: Thursday, June 01, 2017 7:56 AM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: SESARM presentation

Good Morning Anna,
Have you completed your presentation for the SESARM meeting? We are trying to minimize duplication in presentations that will be given by Heather (permitting) and Lynorae (NAAQS implementation/SIPs etc).
If you are still working on it maybe we can have a quick chat related to the presentations. If you have completed it and can share with us that would be great.
Thanks,
Beverly
Sent from my iPhone

To: Ex. 6 - Personal Privacy d@usa.net[Ex. 6 - Personal Privacy @usa.net]
From: Wood, Anna
Sent: Thur 4/20/2017 5:27:37 PM
Subject: Spring Full Deck
2017 Spring Full Deck w_TPs.pptx

Anna Marie Wood

Director, Air Quality Policy Division

OAQPS, U.S. EPA

109 T.W. Alexander Drive

Research Triangle Park, NC 27711

(919) 541-3604

To: Ex. 6 - Personal Privacy usa.net[Ex. 6 - Personal Privacy usa.net]
From: Wood, Anna
Sent: Thur 4/20/2017 4:52:22 PM
Subject: WESTAR Slides
WESTAR Implementation Update_4_19_17.TPs.pptx
WESTAR Ozone_Implementation Update_4_19_17.TPs.pptx

Anna Marie Wood

Director, Air Quality Policy Division

OAQPS, U.S. EPA

109 T.W. Alexander Drive

Research Triangle Park, NC 27711

(919) 541-3604

To: Shaw, Nena[Shaw.Nena@epa.gov]
Cc: vera kornylak[kornylak.vera@epa.gov]
From: Wood, Anna
Sent: Tue 2/21/2017 10:18:06 PM
Subject: RE: Presidential Memo - Streamlining Permitting
nsr-review.pdf
nsr_report_to_president.pdf
timely.pdf

Hi Nena, the weather was also great here. It was a great weekend.

My apologies for not following up on Friday—it ended up being a bit of a crazy day. Attached are the documents I mentioned to you when we talked about the 90 Day NSR study EPA undertook at the beginning of the Bush Administration and the memo we issued on timely issuance of PSD permits under the Clean Air Act. The person you can reach out to is Vera Kornylak. Vera is a senior policy advisor in my division and is very knowledgeable about permitting. I spoke with her on Friday after we talked and she is ready to work on this effort. For your convenience I've copied Vera on this email. Vera has also talked with our permitting folks about data we might have on the number of manufacturing sources that are subject to permitting under the Clean Air Act. Please let me know if you need anything else from me at this point, thanks for your efforts on this, Anna

From: Shaw, Nena
Sent: Tuesday, February 21, 2017 4:37 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: Presidential Memo - Streamlining Permitting

Anna – Hey! Hope you had a great weekend! So beautiful outside.

Do you have the name of the staff person identified for the streamlining domestic manufacturing Tiger Team? It would be so great to have someone this week.

Best, Nena

Nena Shaw

Acting Office Director, Office of Strategic Environmental Management

Office of Policy

(C) 202-564-5106

EPA Employees: click the link to find a broad array of information on the

“Sustainability Community of Practice” SharePoint site

https://usepa.sharepoint.com/sites/OA_Community/Sustainability/SitePages/Home2.aspx

NEW SOURCE REVIEW: REPORT TO THE PRESIDENT

JUNE 2002

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Table of Contents

Overview 1

The Charge to EPA 2

Background 2

Impact on Investment in New and Existing Utility and Refinery Generation Capacity and Energy Efficiency 4

New Sources 5

Existing Sources 8

Impact on Industries Other than Electric Utilities and Petroleum Refineries 22

NSR Applicability 23

Energy Efficiency 25

Impact on Environmental Protection 27

Conclusion 31

New Source Review: Report to the President

Overview

The New Source Review (NSR) program is one of many programs created by the Clean Air Act to reduce emissions of air pollutants – particularly "criteria pollutants" that are emitted from a wide variety of sources and have an adverse impact on human health and the environment. Other key programs include the Title IV Acid Rain Program, "MACT" standards and other air toxics standards, New Source Performance Standards, the 22-state NO_x "SIP Call," the Regional Haze Program, numerous mobile source programs, and other state and local SIP-based emissions standards. Government officials from both major political parties and industry groups have expressed the belief that the NSR program is unnecessarily complicated and often serves as an unnecessary obstacle to environmentally beneficial projects in the energy sector, such as those that improve energy reliability and efficiency and promote the use of renewable resources.

The President's National Energy Policy Development Group asked EPA to investigate whether the NSR program does, in fact, have such impacts. The Agency's review of the NSR program was broad-based. EPA held four public hearings, had individual meetings with over 100 groups representing the public, industry and State and local agencies, and reviewed over 130,000 comments from private citizens, environmental groups, state officials and industry representatives.

With regard to the energy sector, EPA finds that the NSR program has not significantly impeded investment in new power plants or refineries. For the utility industry, this is evidenced by significant recent and future planned investment in new power plants. Lack of construction of new greenfield refineries is generally attributed to economic reasons and environmental restrictions unrelated to NSR.

As applied to existing power plants and refineries, EPA concludes that the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution.

For the refining and other industries, EPA concludes that NSR as applied to existing plants discourages projects that would have provided needed capacity or efficiency improvements and would not have increased air pollution – in fact in some cases air pollution may have decreased. EPA believes this can result in lost capacity or foregone opportunities to increase capacity without increasing emissions.

Finally, with regard to environmental protection, EPA concludes that preventing emissions of pollutants covered by NSR does result in significant environmental and public health benefits. Specifically quantifying the NSR program's contribution to these benefits is very difficult because of the variety of Clean Air Act programs that address these pollutants and because there is no tracking by any government agency of the reductions in emissions that sources make due to the program. Moreover, EPA recognizes that the Agency does not currently have other information that would be necessary to quantify risk reduction benefits associated with the program. However, EPA believes that the inability to make exact estimates does not mean that the benefits of the NSR program are insignificant. EPA also believes, however, that for particular industry sectors the benefits currently attributed to NSR could be achieved much more efficiently and at much lower cost through the implementation of a multi-pollutant national cap and trade program. In particular the President's Clear Skies initiative is a much more certain and effective way of achieving emissions reductions from the power generation sector.

For virtually the entire history of the NSR program, representatives of industry, state and local agencies, and environmental groups have worked with EPA on developing improvements to the NSR program. These efforts came to a head in 1996, when EPA proposed a rule to "reform" the NSR program. Even after the proposal, stakeholders have invested countless hours in trying to find ways to make the program better. Based on the conclusions of this study and the recommendations from the State Governors and Environmental Commissioners[1] and other stakeholders, EPA now plans to finish the task of improving and reforming the NSR program.

I. The Charge to EPA

In its May, 2001 National Energy Policy Report, the National Energy Policy Development (NEPD) Group recommended that the Administrator of the Environmental Protection Agency (EPA), in consultation with the Secretary of Energy and other Federal agencies, "review New Source Review regulations, including administrative interpretations and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection." Consistent with this recommendation, EPA conducted its examination and is now issuing this report. This report describes EPA's conclusions about the impacts of NSR on these three issues based on its review of the available information and comments.

II. Background

EPA assembled an interagency team for this project, including representatives from the Department of Energy (DOE), Department of the Interior (DOI), Office of Management and Budget (OMB), White House Council on Environmental Quality (CEQ), and the National Economic Council (NEC). In consultation with this group, EPA prepared a background paper, which was released on June 22, 2001 (EPA Background Paper). This paper described available data relevant to the three issues EPA was charged with reporting on: investment in utility and refinery capacity, energy efficiency, and environmental protection. The background paper included EPA's own data, as well as data provided in a supporting report by ICF Consulting Inc. (ICF Report), which summarized ICF's survey of the available literature and public statements on NSR issues. The background paper presented the data to facilitate public comment, and to provide the opportunity for external reviewers to provide additional relevant data. The background paper did not draw conclusions or make recommendations.

[1] *See*, Resolution Number 01-12, Environmental Council of States on Reform of the New Source Review Regulations dated August 28, 2001, National Governors Association Policy Position, NR-18 Comprehensive National Energy Policy; Section 18.6.

Following the background paper's release, EPA initiated an intensive public outreach effort, consisting of three components: (1) a 30-day public comment period; (2) a series of four public hearings held in locations across the country; and (3) a series of meetings with more than 100 stakeholder groups, including environmental organizations, industry representatives, and State and local governments. During this public outreach period, EPA received written comments from over 130,000 individuals and organizations. A total of 255 people testified at the four hearings. All of the materials received during the public outreach period, including written comments, transcripts of the hearings, and attendance lists and written materials in connection with the stakeholder meetings, are available in public docket number A-2001-19 at the EPA's Office of Air and Radiation Docket and Information Center.

This report discusses the statutory and regulatory provisions of the New Source Review (NSR) pre-construction permitting program. While the report explains the views of many parties regarding the requirements of the NSR program, it is not intended to affect the NSR program or actions that EPA has taken to implement or enforce the NSR program[2]. This report does not substitute for statutory provisions or regulations, nor is it a guidance document reflecting EPA's interpretation of statutory or regulatory provisions. Its purpose is to summarize information that EPA has received relating to the NSR program and to report on EPA's findings concerning whether the NSR program has affected investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

New Source Review

EPA is strongly supportive of the goals of the NSR permitting program, whose basic requirements are established in parts C and D of Title I of the Clean Air Act (CAA). The purpose of the NSR program is to protect public health and welfare, as well as national parks and wilderness areas, as new sources of air pollution are built and when existing sources are modified in a way that significantly increases air pollutant emissions. Specifically, NSR's purpose is to ensure that when new sources are built or existing sources undergo major modifications: (1) air quality improves if the change occurs where the air currently does not meet federal air quality standards; and (2) air quality is not significantly degraded where the air currently meets federal standards. The fundamental philosophy underlying the NSR program is that a source should install modern pollution control equipment when it is built (for new sources) or when it makes a major modification (for existing sources). Congress believed that incorporating pollution controls into the design and construction when new units are built, or when major modifications occur, is generally more efficient than adding on controls after construction.

The NSR program is by no means the primary regulatory tool to address air pollution from existing sources. The Clean Air Act provides for several other public health-driven and visibility-related control efforts: for example, the National Ambient Air Quality Standards Program implemented through enforceable State Implementation Plans, the NO_X SIP Call, the Acid Rain Program, the Regional Haze

[2] Note that many parties submitted comments concerning issues unrelated to the NEPD's recommendation for EPA to review on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection. For example, numerous parties offered comments as to the merits of pending NSR enforcement cases. This report does not summarize issues unrelated to the NEPD's charge.

Program, etc. Thus, while NSR was designed by Congress to focus particularly on sources that are newly constructed or that make major modifications, Congress provided numerous other tools for assuring that emissions from existing sources are adequately controlled. For example, the national cap on SO_2 emissions established under the Acid Rain Program applies to all existing electricity generating units, without regard to the date of construction or whether a given source has been modified.

NSR operates by requiring a source to obtain a permit prior to construction or major modification. The permit establishes various actions that the source must undertake to control its emissions of air pollution. However, NSR only applies if the construction project will emit air pollution that exceeds threshold levels established in the NSR regulations. For a new source, NSR is triggered only if the potential emissions qualify as major. For an existing major source making a modification, NSR is only triggered if the modification will result in a significant net increase in emissions.

The major NSR program comprises two separate parts: Nonattainment NSR and Prevention of Significant Deterioration (PSD).[3] These two programs have separate requirements to address the differing air quality planning needs in the areas where they apply. Nonattainment NSR applies in areas where air is unhealthy to breathe - i.e. where the established national ambient air quality standards (NAAQS) for a CAA criteria pollutant are not being met. These areas are called nonattainment areas. Nonattainment NSR for major sources of certain pollutants also applies in the federally designated ozone transport region (OTR), which consists of eleven northeastern States and Washington, D.C.[4] PSD applies to major sources located in areas where air quality is currently acceptable - i.e., where the NAAQS for CAA criteria pollutants are being met. These are called attainment areas. Because nonattainment areas have poorer air quality, nonattainment NSR requirements are generally more stringent than PSD requirements.

III. Impact on Investment in New and Existing Utility and Refinery Generation Capacity and Energy Efficiency

The EPA begins by examining the question of whether the NSR program has an impact on investment in projects that would increase or preserve utility and refinery generation capacity or that would improve energy efficiency. We received extensive comments on this issue, reflecting widely varying views on whether there is an impact and, if so, on its nature and extent.

In general, comments made by both the electric utility industry and the petroleum refining industry consistently assert that the NSR program has a significant and adverse impact on investment in expanding and preserving capacity, as well as on energy efficiency.[5] These commenters assert that the

---

[3] The term NSR usually refers to the overall program, but is sometimes also used as shorthand to refer to nonattainment NSR, which may be a source of confusion. In this document, we will use NSR to refer to the general program (both nonattainment NSR and PSD), and will use nonattainment NSR when referring specifically to NSR for nonattainment areas.

[4] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Washington, D.C.

[5] These comments were consistently raised by companies representing virtually all types (*e.g.*, coal-fired; oil-fired or gas-fired) and sizes of electric generating facilities. *See, e.g.*, Comments of the Clean Energy Group (CEG) [II-D-291]; Comments of the Utility Air Regulatory Group (UARG) [II-

program is in need of fundamental reform. Other industries (as discussed in Section IV below) made similar assertions, as did some State permitting authorities. These commenters said that investment is hindered by (1) regulatory uncertainty and lack of flexibility resulting from alleged recent policy "re-interpretations" related to the applicability of the program's requirements; and (2) the added costs and delays imposed by the NSR process.[6] Other commenters, including environmental groups and some State and local permitting authorities, expressed the opposite view. They assert that NSR does not appear to be significantly hindering such investment, adding that NSR has resulted in large benefits to the environment while allowing for increased energy and/or fuel supplies.[7] One environmental commenter does not believe that there is sufficient information to conclude that NSR is a primary factor driving decisions to invest or not to invest in capacity.[8]

This section discusses our conclusions based on a review of the available data and comments received regarding investment in new capacity and energy efficiency. Because the issues associated with new and modified source permitting differ, this paper will discuss separately the impact on new sources and the impact on existing sources undergoing changes.

A. New Sources

Focusing first on the impacts of NSR on investment in new capacity, the EPA finds that NSR does not appear to have a significant impact on investment in new utility or refinery plants. The discussion below indicates that, for utilities, significant new capacity has been permitted in recent years and substantial additional greenfield capacity is planned. For refiners, decisions about whether to construct new greenfield refineries are primarily driven by economic and environmental considerations. It does not appear that NSR has a significant impact on these considerations.

1. *Utilities*

D-303]; Comments of Class of '85 Regulatory Response Group (Class of '85 Group) [II-D-268]; Comments of National Rural Electric Cooperative Associations (NRECA) [II-D-322]. The members of these groups, as well as individual utilities that filed comments expressing the same conclusion, span the entire United States. *See, e.g.*, Comments of Northeast Utilities Service Company (NUSCO) [II-D-331]; Comments of Cinergy [II-D-270]; Comments of Sunflower Electric Power Corporation [II-D-292]; Comments of Tri-State Generation and Transmission Association [II-D-335]; Comments of West Associates [II-D-216]; Comments of Salt River Project (SRP) [II-D-320]. Even waste-to-energy facilities agreed with this conclusion. *See e.g.*, Comments of American Ref-Fuel [II-D-214]. The refining industry offered similar comments. *See* NPRA Letter to Stephanie Daigle, EPA, 7/23/2001.

[6] See comments by Michigan Department of Environmental Quality, representing a workgroup including Alabama, Michigan, North Carolina, South Carolina, Virginia and West Virginia permitting staff. [II-E-09].

[7] For other State comments, see STAPPA/ALAPCO, [II-D-313], CARB [II-D-468], RAPCA [II-D-302], Wisconsin, Missouri, et. al. For environmental groups, see, Clean Air Task Force [II-D-236], NRDC, Sierra Club [II-D-437], et. al.

[8] See Natural Resources Defense Council (NRDC) comments [II-D-267] at 1.

For electric utilities, significant new sources were permitted in recent years (dominated by natural gas-fired systems) and more are planned. The background paper noted current plans of certain companies to bring into service units producing more than 120 Gigawatts (GW) in the coming years. An analysis by the NorthBridge group, prepared for the Clean Air Task Force, uses RDI's NewGen database to estimate that it is likely that 214 GW - and possibly as much as 400 GW - of new generating capacity will come online before 2005, based on a survey of data on plants at various stages of development.[9] Several State commenters presented similar data. For example, New Jersey stated that it had permitted over 2500 MW of new electric generation since July 1999, and had proposed to approve another 1700 MW in July of 2001[10]. Another 5800 MW of applications were under review, and another 2000 MW of projects were in the pre-application meeting stage. These projects cover 22 facilities and 49 units. This 12,000 MW will result in a 60% increase over the 18,000 MW of existing generating capacity in New Jersey.[11] Other States and environmental group commenters presented similar data.[12] Although most of these projects will be subject to NSR, the program does not appear to be hindering their development.

In general, the DOE's experience is that far more capacity is planned than is ever actually realized. As it related to the analysis by the NorthBridge group, the DOE projects in its 2001 Annual Energy Outlook that only a small fraction of the capacity estimates by NorthBridge will actually come on line by 2005. For the period of 1999 to 2005, DOE estimates the following:

- Overall generation will increase from 3386 billion kilowatt-hours (BKWH) to 3810 BKWH.
- Overall capacity will increase by 74 GW (from 745 gigawatts (GW) to 819 GW).
- For coal-fired power plants, capacity will decrease slightly (from 306 GW to 301 GW), while generation increases from 1833 BKWH to 2085 BKWH, as existing units increase their hours of operation.
- For gas-fired plants, combined-cycle units will increase in capacity from 20 GW to 50 GW, while generation increases from 371 BKWH to 584 BKWH.

While these data indicate continued expansion in new generating capacity, some industry commenters assert that NSR can nevertheless introduce costs and delays to the process of bringing new generating units online, as well as have an impact on fuel supply flexibility. Utilities cited implementation of the requirements for preconstruction monitoring, modeling, and consultation with

---

[9] This 214 GW increase would represent a 30 percent increase over the current installed capacity level, and would restore national reserve margins to about 25 percent, from a low of 8 percent in 1999.

[10] See New Jersey DEP comments [II-D-310].

[11] The State of Kentucky, in fact, put a hold on any new permit applications for electrical generation sources until it can analyze the environmental impacts of the large volume of pending permit applications.

[12] See, e.g., California Air Resources Board (CARB) [II-D-468], Georgia Department of Natural Resources (DNR) [II-D-341], Wisconsin DNR [II-G-71], STAPPA/ALAPCO [II-D-303], Clean Air Task Force [II-D-236], NRDC [II-D-267] and other similar comments.

Federal Land Managers, saying that the processing time by Federal, State and local governments and potential permit appeals can result in significant costs and delays in obtaining a permit. In particular, industry commenters, as well as some State permitting authorities, attribute a significant portion of the delay in obtaining NSR permits to the large body of NSR guidance that has been issued over the course of many years, by both EPA and State agencies administering delegated programs. This guidance frequently is case-specific in nature. Many commenters consider the guidance to be ambiguous and, in some cases, inconsistent.

Among the various aspects of the NSR program that industry commenters more specifically identified as concerns for new sources included the following:

- How to determine which emissions control technologies qualify as best available control technology ("BACT") or lowest achievable emissions rate ("LAER") technology using EPA's "top down" policy and the Agency's BACT/LAER clearinghouse.

- Procedural concerns about guidance issued by Federal Land Managers related to permitting near Class I areas.

- The limitation on construction activities prior to issuance of a permit, which is of particular concern when (1) the permit undergoes lengthy appeals processes, or (2) the climate is cold and the construction season is thus shorter.

- The cost and availability of offsets in nonattainment areas. Commenters, particularly in California and New York, noted that shortages in available offsets have the potential to significantly increase the cost of NSR permitting in certain limited areas. Permitting authority commenters noted that offsets represent from 1-6 % of the cost of a new power plant.[13]

Commenters further stated that NSR control requirements affect fuel supply choices for new installations. They point out that the cost of air pollution control represents a much greater proportion of the cost of construction at coal-fired facilities than at gas-fired plants.[14] Operation and maintenance costs are also higher. They believe this discourages investment in new coal-fired plants.

Other stakeholders offered a different view. Several State and local permitting authorities noted that the NSR process can generally be accomplished in a reasonable time, and within the same time frame as the other elements involved in planning of a typical electric generator project.[15] Some States reported acceleration of permitting times for new utility sources consistent with that reported in

[13] STAPPA/ALAPCO comments [II-D-313] at 6.

[14] The primary air pollution control requirement commonly imposed on natural gas combustion is selective catalytic reduction, which adds about $30 per kilowatt to the cost of a combined cycle generation system. New pulverized coal systems require electrostatic precipitators or fabric filters for particulate matter control, scrubbers for sulfur dioxide control, selective catalytic reduction for nitrogen oxide control, and perhaps additional control technology for air toxics. Cumulatively, the systems needed for coal-based generation cost over $200 per kilowatt, and add about 20% to the cost of a new coal-fired system. For a 1000 MW unit, these translate into a cost of $200 million.

[15] See, e.g., STAPPA [II-D-313] at 3, New Jersey DEP [II-D-310] at 2.

the EPA Background Paper.[16] One State commenter suggested that the perception that NSR is lengthy, cost-intensive, and uncertain is really not the norm, though it can be true in exceptional cases.[17]

In EPA's experience, NSR has, in some individual cases, impeded new power projects. However, as a general matter, available information indicates that NSR typically does not represent a significant barrier to the construction of new electricity plants. As for the impact of NSR on fuel choices for new facilities, EPA notes that NSR typically does not require significantly greater levels of control at new coal-fired plants than the recently updated NSPS for large electric generating units. Thus, NSR itself is not the only driver with regard to air pollution control costs at new coal-fired units and does not appear to significantly influence fuel choices at new facilities.

2. *Refineries*

As noted earlier, the construction of new "greenfield" petroleum refineries in the near future seems unlikely for various economic and regulatory reasons, primarily unattractive profit margins. Industry has reported that the rates of return for refineries have averaged about 5 percent in the last decade, roughly equivalent to the return from a passbook savings account, but with much greater risk. As a result, building new plants at new sites is highly unlikely.[18] The EPA agrees with this assessment. Moreover, while any new refinery would be required to obtain an NSR permit, the available information does not indicate that NSR permitting is among the most significant impediments to the construction of new refineries. Refinery commenters indicate that any additional U.S. refinery capacity must come from either efficiency improvements or expansion at existing refineries (discussed below).

B. Existing Sources

The vast majority of concerns about NSR raised during the review pertained to existing sources. As discussed below, the EPA believes that commenters have identified areas where NSR can discourage investment in both preserving and maintaining utility and refinery generating capacity as well as in improving energy efficiency and expanding capacity.

1. *Utilities*

With respect to existing sources, comments from across the spectrum of the utility industry consistently asserted that the NSR program imposes significant burdens on the utility practices necessary to maintain the safety, availability, efficiency and reliability of the electricity supply at existing sources. They further assert it can have a highly negative impact on the nation’s power supply. The result, they conclude, is that the program hinders investment in projects intended to expand and preserve generating capacity at existing electric generation units. In addition, as discussed below, many utility commenters believe that the current NSR program has actively discouraged efficiency

[16] See CARB [II-D-468]at 4.
[17] Wisconsin DNR comments [II-G-71] at 1.
[18] See, Testimony of the National Petrochemical and Refiners Association (NPRA) before the Senate Subcommittee on Clean Air, Wetlands, Private Property and Nuclear Safety on Apr. 5, 2001.

improvement projects, which they believe not only can have net environmental benefits, but also can provide an effective short-term response to tight reserve margins at many locations in the United States. On the other hand, environmental groups do not believe that there is sufficient information to conclude that NSR is the primary factor driving decisions to invest in new capacity at existing sources or that, absent NSR, significant investments would have been made that are presently not being made in recapturing lost existing capacity due to deterioration of equipment. This section examines more closely the capacity issues at electric utilities, followed by the energy efficiency issues.

a. Impact on Utility Projects to Maintain the Availability, Reliability, and Safety of the Electric Power Supply

(i) *NSR Applicability*

The utility industry comments predominantly focused on the exclusion from major NSR permitting requirements for activities that represent "routine maintenance, repair and replacement." They asserted that, in recent years, EPA has narrowed its interpretation of this exclusion to the point where NSR potentially applies to repair and replacement activities that are customarily undertaken within the industry to assure the availability, reliability, and safety of power plant operations. Commenters believe that under such an interpretation NSR would be required whenever the work involved: (1) a component that is replaced infrequently in the life of an industrial facility; (2) a component that is large and expensive (in absolute terms); or (3) a replacement component that is better designed and will improve the availability or efficiency of the facility.

Thus, according to the utility commenters, because electricity generation units are inherently large, complex, and expensive (in absolute terms), most power plant repair and replacement activity would not be covered by the exclusion. Because of the costs and potential delays associated with NSR, they believe that this has discouraged activities intended to maintain the reliability, availability, and safety of existing power plants; and/or has required generators to limit the output of their power plants to avoid triggering NSR, regardless of their capacity, in order to maintain the units during their normal useful lives. NSR costs and delays are of particular concern to commenters for such changes at existing units because (1) while certain projects might be relatively inexpensive absent NSR, they believe the cost of controls resulting from NSR can make them cost-prohibitive to undertake, which, in turn, can adversely affect the availability and reliability of plant operations and discourage such projects, and (2) they believe that units may need to be offline until permitting can occur, so delays in permitting can have significant impacts on energy supply through lost generation during this time.

Although utilities stated that NSR-required controls are expensive relative to the gains associated with projects that might trigger NSR, other commenters noted that these costs are small compared to the company's revenue. The Clean Air Task Force submitted a study by MSB Energy Associates performed on a sample of 51 existing coal-fired utility units. The study concludes that if these units triggered NSR and had to install BACT-level controls, the cost would be modest relative to the size and revenue level of the companies.[19] In the commenters' view, this impact is exchanged for significant environmental benefits, estimated at 2.8 million tons per year of sulfur dioxide (SO_2) (22% of

[19] See Clean Air Task Force Comments [II-D-236], Appendix D.

all power plant SO_2 emissions in the U.S.) and 1.0 million tons per year of NO_X (19% of all power plant NO_X emissions in the U.S.).

According to industry, thousands of repair and replacement projects are undertaken by facilities each year and that, as a result, NSR permitting is potentially triggered early in the life of virtually every electric utility plant, and then repeatedly thereafter.[20] The industry commenters submitted information about the types of projects they stated that they typically undertake, which they maintain are required to ensure reliability, availability, or safety of their facilities, but which they believe EPA would classify as non-routine and therefore would potentially be subject to NSR if they resulted in a significant net emissions increase.[21]

For example, a survey undertaken by the Tennessee Valley Authority (TVA) reported the frequency with which particular repair and replacement projects are undertaken within the electric utility industry.[22] The TVA survey covered approximately 20% of the electric utility industry -- 219 units totaling about 80,000 MW -- and included a review of case studies and statistics regarding cyclone replacement, balanced-draft conversion, reheater replacement, and economizer replacement. For example, their survey states that, at the 190 units in the survey that had reheaters, there were 213 reheater replacement projects (some reheaters were replaced more than once). At the 202 units in the survey that had economizers, there were 98 economizer replacement projects. For both components, replacements occurred as early as 5 years after initiation of a unit's commercial operation, or as late as 40 to 50 years. Similarly, at 151 boilers originally constructed as forced draft systems, utilities replaced 79 systems with balanced draft systems, primarily to address "equipment degradation, maintenance problems, health and safety concerns, and pollution control requirements."[23] Finally, the TVA survey reported that, since 1979, 300 cyclones out of 701 had been replaced at the 96 electricity-generating stations in the United States powered by cyclone boilers. UARG similarly reported a more complete, recent census of the entire coal-fired steam electric generating industry.[24] This census sought industry-wide information regarding the frequency of maintenance, repair and replacement activities that they believe EPA considers non-routine. The census results are reported to show:

- The industry has undertaken tens of thousands of such maintenance, repair or replacement activities;
- Every unit in the industry has undertaken such activities;
- Approximately 50% of the units in the industry will have undertaken such activity within five years of the unit's in-service date;
- Each unit in the industry undertakes on average annually at least one such activity.

---

[20] UARG Comments [II-D-303] at 29-32.

[21] UARG Comments [II-D-303] Attachment C.

[22] *See* Jerry Golden, TVA, *Routine Maintenance of Electric Generating Stations* (February 2000) ("TVA 2000 Report"), *described in* UARG Comments [II-D-303] at 29-31.

[23] TVA 2000 Report at 25.

[24] UARG Comments [II-D-303] at 31-32.

In short, in the view of many industry commenters, an inappropriately narrow routine maintenance exclusion would not exclude many common maintenance projects. According to these commenters, this would leave nearly every coal-fired generating unit in a constant state of obligation to evaluate whether each of these numerous projects would trigger NSR, and if so, whether the costs associated with NSR (including, if applicable, the costs of add-on controls and potential downtime) would render such projects cost-prohibitive. As discussed below, if such projects are found to be cost prohibitive, commenters predict steady deterioration of existing capacity, and limited investment in the recovery of such capacity at existing sources. Many industry commenters echoed this conclusion and asserted that the situation is unacceptable and must be corrected to reflect the real environment surrounding routine maintenance within the electrical utility industry.[25]

On the other hand, environmental group commenters and some permitting authorities felt that the routine maintenance exclusion is appropriate. They believed that a less narrow exclusion would allow the exception to swallow the rule. In this vein, commenters expressed concerns that large-scale capital projects, such as major life extension projects, should not qualify as routine.[26] One of these commenters expressed concern that a facility could be virtually rebuilt without triggering NSR under industry's preferred interpretations of the routine maintenance exemption[27].

After reviewing the comments, the EPA notes that there are differing opinions amongst the commenters about the appropriate scope of the routine maintenance exemption and the resulting NSR impacts. In determining whether an activity is "routine" for purposes of being excluded from NSR, EPA consistently has taken a case-by-case approach, weighing the nature, extent, purpose, frequency and cost of the work, as well as other relevant factors. Nevertheless, the Agency recognizes that many industry commenters expressed uncertainty about the scope of the routine exclusion and argued that this uncertainty will cause them to delay or forego projects critical to maintaining the availability, reliability and safety of their facilities. In light of the volume of anecdotal evidence presented, the EPA concludes that concern about the scope of the routine maintenance exclusion is having an adverse impact on projects that affect availability, reliability, efficiency, and safety. Changes to the NSR program that add to the clarity and certainty of the scope of the routine maintenance exclusion will improve the process by reducing the unintended consequences of discouraging worthwhile projects that are in fact outside the scope of NSR.

(ii) *Energy Impacts*

According to utility commenters, the energy impact of an inappropriately narrow NSR routine maintenance exclusion would be adverse and potentially quite significant. In addition, the industry commenters stated that an inappropriately narrow exclusion would leave many activities potentially

---

[25] NRECA Comments [II-D-322] at 14-15; *see also* Class of '85 Group Comments [II-D-268] at 9 ("Electric generating plant personnel have been placed in the untenable position of not being able to correct and improve the reliability and efficiency of their plants, resulting in compromised safety to plant employees and the general public, without risking an enforcement action."); Dairyland Comments (II-D-324) at 4 (EPA's current "interpretation may compromise the reliability and efficiency of existing plants and could undermine the preservation of a diverse energy supply.").

[26] See, e.g., RAPCA [II-D-302], Adirondack Council [II-D-136], Public Citizen [II-D-327].

[27] Public Citizen [II-D-327].

subject to NSR. This circumstance, they believe, would result in limited alternatives for utility managers. They describe three alternatives.

First, utilities could go through the NSR pre-construction permitting process. The principal complaints against this alternative were protracted processing delays and the attendant costs, including the costs of pollution control retrofits.[28] In addition, commenters feared that, if the interpretation of routine were to be narrowed, thousands of projects would trigger NSR per year, and would result in even more substantial delays by flooding the permit process with more permit applications than it has the capacity to process quickly.

Second, a company could accept enforceable emissions limits (through a "minor" NSR permit) in the form of a cap on emissions from the affected units.[29] Commenters stated, however, that acceptance of such a cap would require a utility to limit the affected unit's hours of operation and production rates to representative emission levels just prior to the change, which could restrict the electricity supply in a particular area.[30] Commenters also could limit emissions by adding pollution control technology, but commenters felt this was also not a workable NSR avoidance strategy because it also could be infeasible, cost-prohibitive, and would only be a temporary solution.[31] Moreover, commenters stated that the delays associated with the minor NSR process required to create the limit still severely impact a unit's ability to replace components necessary to get back online quickly after a forced outage.[32] For example, when a turbine rotor shaft cracks or slag falls and destroys a boiler floor, the utility must repair the component as quickly as possible and restore the unit to service. Commenters claim that, if the necessary repairs were not considered routine maintenance, repair and replacement, the repair could not be made until the source obtained an NSR permit. In the meantime, the commenters believe that the utility could lose the entire capacity of the unit, which could endanger the stability of the electrical grid and create a risk of regional blackouts.[33]

Commenters also argued that avoiding NSR by accepting caps on emissions through operational limits would constrain electrical system operators' flexibility to deliver necessary electricity at the least cost. In this regard, several utilities analyzed their systems to estimate the restrictions on their ability to produce electricity, had what they consider to be a narrow interpretation of the routine exclusion been applied over the last twenty years and had the utilities elected to obtain minor NSR permits limiting generation to recent levels in every instance they undertook certain replacement projects.

---

[28] *See, e.g.*, Class of '85 Group Comments [II-D-268] at 9-10.

[29] Commenters also complained of delays in the minor NSR permitting process (an average of 3-8 months in one utility's service area.) *See* Jerry L. Golden & Donald P. Houston, TVA, *Impacts of EPA's Reinterpretation of New Source Review Requirements -- Potential Loss of Generating Capability on the TVA System,* at 8 (July 19, 2001) ("TVA 2001 Report") (Attachment E to UARG Comments [II-D-303]).

[30] *See* UARG Comments at 39-42; *see also* EPA Background Paper at 7.

[31] *See* UARG comments at 39-42.

[32] See, e.g., Class of '85 Group Comments [II-D-268] at 7, TVA 2001 report at 7 (Attachment E to UARG Comments [II-D-303]).

[33] *See, e.g., id.*

For example, TVA (serving approximately 2.3 million homes in the Tennessee River Valley),[34] reported that, over the last twenty years, it would have lost 32% of its coal system's energy capability, or 34 million megawatt-hours (MW-hr) annually. In a similar analysis, the Southern Company found that, by the year 2000, it would have had an energy shortfall of 57.5 million MW-hr, and that it would not have been able to meet 38% of its customer demand.[35] Similarly, First Energy estimated that it would have lost 39% of its coal-fired generating capacity between 1981 and 2000.[36] West Associates (a western utility with a younger fleet of generating units) estimated a loss of 27% of generating capacity of one of its plants just in the next six years. West Associates also estimated that, after 10 years of operation under this "cap system," the Western System Coordinating Council (WSCC) would have lost 65 million MW-hr of generating capacity, or the equivalent of 32 power plants with a net capacity of 250 MW each.[37] The National Rural Electric Cooperative Association (NRECA) estimated that, in one maintenance cycle, the loss of capability for the approximately 21,000 MW of cooperative-owned plants would be 12% to 24%.[38] Nationally, using this analysis method, one commenter stated that it would take 200 new 500 megawatt power plants just to make up the lost capacity, that is, to stay at the current levels of available supply.[39] Maximizing the utilization of existing generation capacity can be critical to ensuring the ability of utilities to meet consumer demand in peak periods.

Third, according to industry commenters, a company could simply choose not to undertake the needed maintenance, repair and replacement projects in question, so as to avoid triggering NSR. They believe this would result in a loss of electricity generating capacity, because delayed and foregone maintenance leads to a decrease in availability and reliability.

In addition, commenters suggest that such a decrease also could have a negative impact on the energy efficiency of the unit and the overall efficiency of a utility system. This is because, if a larger utility unit becomes unavailable during a period when it would have been utilized to meet consumer demand, then multiple smaller, less efficient units often must be utilized in its place.[40] One utility commented that only through maintenance of highly efficient low-cost baseline generation is the retirement of more inefficient units possible.[41] The commenter asserted that less efficient units are more costly to operate and generally produce more pollution per unit of electric output.

---

[34] TVA 2001 report at 12-14.

[35] Southern Company, *The Dismantling of Energy Supply Capacity Through New Source Review* (Attachment D to UARG Comments [II-D-303]).

[36] First Energy Comments [II-D-261] at 1.

[37] West Associates Comments [II-D-216] at 7.

[38] NRECA Comments [II-D-322] at 7. Other commenters that submitted similar analyses include: Minnesota Power Comments [II-D-165] (25% lost production); Dairyland Comments [II-D-324] at 7 (41% lost generating capacity); SRP Comments [II-D-320] at 6 (18.5% loss).

[39] *See* UARG Comments [II-D-303] at 39.

[40] *See* Ralph L. Roberson & Richard D. McRanie, Thoughts *on Power Plant Efficiency*, at 7 (Attachment F to UARG Comments [II-D-303]) (RMB Report); *see also* Class of '85 Group Comments [II-D-268] at 5-6 (noting that utilization of base-loaded units displaces less efficient, more polluting plants).

[41] First Energy Comments [II-D-261] at 1.

EPA notes that the possible energy impacts predicted by industry commenters appear to flow from the industry's reported uncertainty regarding the scope of the routine maintenance exclusion. Consistent with our conclusion in the previous section of this report, we conclude that concern about the scope of the routine maintenance exclusion is having an adverse impact on projects that would improve the reliability and availability of existing electric generating facilities. We also note that, when catastrophic forced outages have occurred in the past, the Agency has consistently worked with industry and State and local permitting authorities to allow the facility to get the unit back and running quickly.

B. Impact on Efficiency Improvement Projects

(i) *NSR Applicability*

With respect to the issue of energy efficiency, a significant number of industry commenters stated that an inappropriately narrow routine maintenance, repair and replacement exclusion would prevent electricity generators from taking advantage of opportunities to improve their generating efficiency. One measure of such efficiency is "heat rate," or the amount of fuel-bound energy required to produce a unit of electrical power (typically expressed in million BTU per kW-hr). Improving an electric unit's efficiency – *e.g.*, its heat rate -- means that less fuel is required to produce the same amount of electrical power, reducing pollution per unit of production output. Alternatively, improved efficiency may allow a unit to produce more electricity for the same amount of fuel burned (*i.e.*, with no greater amount of emissions). New electric generation technologies often lead to energy efficiency improvements, but industry raised concerns that applying these new technologies (*i.e.*, replacing boiler or turbine components with components of better design and materials) often could trigger NSR – in some cases even if the unit's emissions rate does not increase – because the source uses the more efficient unit more than it used the old one.

These commenters stated that the turbine blade project that was the subject of the Detroit Edison applicability determination is a good example of such a project.[42] Industry reports that, under a voluntary self-reporting program initiated by the Energy Information Administration (EIA), utilities have reported numerous projects that are expected to increase efficiency.[43] Commenters cited as examples projects ranging from load optimization programs and improved boiler controls to replacing turbine blades and rotors, to upgrades or replacements of components like superheaters and condensers. [44]

Industry commenters noted that EPA views such energy efficiency projects as the Detroit Edison turbine blade upgrade as "markedly different from the frequent, inexpensive, necessary, and

---

[42] EPA Background Paper at 28.

[43] RMB Report at 6 (Attachment F to UARG Comments [II-D-303]).

[44] Industry commenters state that most energy efficiency improvements can be linked with tangible benefits to the environment and that unless the power source is in close proximity to the process in which energy efficiency is improved, the emissions benefits are not necessarily local. If the power source is a grid, it may not be possible to predict where all the benefits will occur, nor what their magnitude would be. Nevertheless, commenters believe that energy efficiency should be an important aspect of meeting national air pollution goals because the energy saved is energy that would have otherwise been generated.

incremental maintenance and replacement" of deteriorated components and, therefore, not within the scope of the routine maintenance exclusion.[45] Industry commenters expressed concern that this could result in the discouragement of energy efficiency improvements because they could be subject to NSR. For utilities, this is a particular concern in any jurisdiction that has not incorporated the WEPCO rule emission increase methodology because the "actual-to-potential" test applies in these jurisdictions.[46] In non-WEPCO jurisdictions, and in all jurisdictions for non-utility activities, industry commenters said that NSR could apply to any project that both corrects availability/reliability problems and improves efficiency (because of the belief that any project that corrects availability/reliability problems could result in an emissions increase under the actual-to-potential test), and to any efficiency improvement project at a unit that is not at the very top of a system's loading order. Even for units that are at the top of the loading order of a particular system, like Detroit Edison's Monroe units, industry commenters expressed concern about whether any efficiency improvement could be shown not to increase emissions, because an efficiency improvement almost always makes the improved unit more attractive to run.

Utility commenters stated that the Detroit Edison applicability determination discourages utilities from undertaking efficiency improvement projects.[47] They suggested that utilities are likely to forego efficiency improvements in order to avoid the uncertainty, delays and potential costs associated with NSR applicability. One commenter sought to illustrate this point in responding to the EPA Background Paper's inquiry regarding whether NSR applicability alters the economics of efficiency improvement projects by evaluating a typical turbine efficiency improvement project. This evaluation showed that such a project would cost approximately $937,000 for a 250 MW unit, and would be expected to yield additional revenues of $21.5 million (present value). For such a unit, however, the commenter determined that NSR applicability would result in expensive retrofits, with a capital cost (*i.e.*, excluding operation and maintenance of the retrofits) approximating $68.4 million.[48]

Industry commenters said that discouraging efficiency improvement projects also results in more emissions than if the projects could go forward without NSR. They argue that, on a megawatt basis, efficiency improvements reduce pollution,[49] and that, even if utilization increases at the unit with improved efficiency, the dynamics of economic dispatch of electric generating units mean that the increased utilization at that unit necessarily displaces less efficient, and therefore more-polluting, plants.[50] Thus, the industry concludes that discouraging efficiency improvements almost always results in higher emissions than if these improvements had been made. As an example, the Detroit Edison case was again cited, where the use of the more efficient blades would have permitted each generating unit to produce the same amount of electricity as it had in 1994 while burning 112,635 fewer tons of coal. The

[45] EPA Background Paper at 28 (citing Detroit Edison Applicability Determination, May 23, 2000).

[46] Under EPA's "WEPCO rule," NSR is not triggered for existing utility sources unless there is a significant net increase in actual emissions using an actual to predicted future actual methodology.

[47] *See, e.g.*, Class of '85 Group Comments [II-D-268] at 5; UARG Comments [II-D-303] at 45.

[48] *See* Comments of Xcel Energy [II-D-213] at 6-7.

[49] EPA Background Paper at 28.

[50] *See* Class of '85 Group Comments [II-D-268] at 5-6; *see also* FirstEnergy Comments [II-D-261] at 1-2.

result, according to commenters, would have been a reduction of 1,826 tons per year (tpy) in SO_2 emissions, 1,402 tpy in NO_X emissions, and 259,111 tpy in carbon dioxide (CO_2) emissions, assuming that input design parameters (maximum heat input and fuel consumption specifications) remained the same. Detroit Edison estimated that more than 1,000 other electric utility units in the United States have the capability to achieve similar reductions through similar turbine blade replacements and other projects; thus, extrapolating based upon these estimates, they predict that by encouraging the adoption of blading efficiency improvements, CO_2 emissions would be reduced by 81 million tons per year or more, provided input design parameters (maximum heat input and fuel consumption specifications) remained the same. They predict that SO_2 and NO_X emissions would also be reduced significantly.

In contrast, commenters from environmental groups believe that NSR treats energy efficiency improvement projects appropriately. They stated that NSR only applies when a project results in an emissions increase and that the types of projects discussed above where significant reductions are achieved would not trigger NSR. However, if an energy efficiency project also results in a significant emissions increase, these commenters felt that it would be inappropriate to exempt the increase from review under NSR.[51] One commenter also questioned whether NSR is the predominant factor in influencing a decision about whether to proceed with an efficiency project, noting that some analysts believe that the regulation of utility rates – and specifically their treatment of cost recovery – has lessened the incentive for heat rate improvements.[52]

In reviewing the information regarding energy efficiency projects, the EPA concludes that NSR may discourage some energy efficiency improvements. EPA notes that as long as utilization remains constant, energy efficiency improvements can result in significant emissions reductions. Such projects would not trigger NSR if there were not a significant emissions increase.[53] Because such projects are not subject to the NSR regulations, NSR generally has a negligible impact in such cases. However, as noted above, energy efficiency improvements are often associated with increases in utilization, because the more efficient generating units are dispatched more often. Efficiency improvements can also result in an increase in capacity or availability. In such cases, there can be local emissions increases that trigger NSR if the projects are not routine maintenance. For example, in Detroit Edison, if a five percent increase in operation were to result, actual increases on the order of 800 tons of NO_X and 2000 tons of SO_2 would occur. Even if these emissions increases occur at the same time as emissions decrease somewhere else, some commenters expressed concerns about the localized impacts of potentially large emissions increases, and felt that review under NSR was needed to address them.

Congress provided that where physical changes at a plant result in significant increases in air pollution, these plants should go through NSR and take steps to control emissions. Even if a physical change is relatively inexpensive when compared to the cost of the controls that are projected to result from NSR, the change could still result in emissions increases that Congress believed should undergo review. However, as noted in the example turbine efficiency improvement project above, and echoed throughout many comments, the costs associated with NSR, particularly the costs to retrofit pollution controls, can render these projects uneconomical. Thus, the EPA finds that NSR discourages some

[51] See, e.g., July 20 testimony of John Walke, NRDC.

[52] NRDC Comments [II-D-267].

[53] This was the case in Detroit Edison, where there was no expected increase and therefore the proposed project did not trigger NSR. [See Detroit Edison Applicability Determination]

types of energy efficiency improvements when the benefit to the company of performing such improvements is outweighed by the costs to retrofit pollution controls or to take measures necessary to avoid a significant net emissions increase. The EPA recognizes the need to promote the development of efficient and more environmentally friendly designs.

On the other hand, it is also clear that a wide range of activities at an electric utility can have energy efficiency benefits, from everyday maintenance to major capital projects. In general, the EPA encourages efficiency improvements wherever feasible. However, the scope and magnitude of some of the kinds of changes, their impact on recovering capacity that had been lost to deterioration of equipment, their impact on significantly extending the life of the boiler, turbine, etc., and the resulting significant emissions increase, necessitates that certain projects which may result in efficiency improvements, must be reviewed under NSR. Though projects of this magnitude still may go forward once their air quality impacts are addressed, the EPA finds that NSR can discourage companies from undertaking them.

(ii) *Energy Impacts*

The ICF report in support of the EPA Background Paper referred to various data, such as those of the National Coal Council (NCC) May 2001 report, which estimate that repairs and replacements that improve efficiency at existing coal-fired facilities could result in an increase in capacity of 5% to 10%. Applied across the entire coal-fired electric generation capacity of the United States (over 300 GW) this would result in an additional capacity of 15,000-30,000 MW. This is the equivalent to 30-60 new 500 MW plants or enough power for 10-20 million homes.

Similarly, as noted in the EPA Background Paper, the NCC report found that coal-fired units over 20 years of age had been substantially derated, and concluded that: "If all existing conditions resulting in a derating could be addressed, approximately 20,000 MWs of increased capacity could be obtained from regaining lost capacity due to unit deratings." Likewise, the NCC reported that 20,000 MW of additional capacity could be gained by "increasing heat input and/or electrical output from [existing] generating equipment." Moreover, the NCC found that this restoration and increase of capacity from existing units could only be economically viably pursued by the facility owners if, among other factors, the increased availability and/or electrical output would clearly not trigger NSR. Other industry representatives supported this estimate.

Conversely, environmental group commenters expressed the view that such investments are not as profitable as investments in completely new electric generation capacity and that this is why the industry is not pursuing them, as opposed to NSR being the major impediment.[54] They also estimate that the emissions reductions from efficiency improvement projects would be small compared to the reductions that would be achieved if NSR applied.

In conclusion, for the utility industry, with respect to existing sources, and in contrast to new sources, the EPA finds that the available information indicates that the NSR program is having an adverse impact on investment in both electric generation capacity and energy efficiency. While there are only limited data that prove that NSR has resulted in the cancellation of otherwise economical

---

[54] Clean Air Task Force comments [II-D-236] at 49 and App. C.

projects of either type, a significant number of industry commenters presented a variety of projects at existing sources that could have increased capacity, improved reliability, or enhanced efficiency, but were made uneconomical due to delays and costs associated with NSR. The EPA finds many of these cases to be credible and based on real-world examples, and believes that they demonstrate that NSR has an adverse impact on such investment at existing sources. It is reasonable to conclude that the foregone investment has resulted in foregone capacity increases through decreased reliability and availability that are not recovered, and through foregone efficiency improvements.

2. *Refineries*

Turning to the question of NSR impacts on investment in capacity at existing refineries, the EPA finds that the comments again highlight areas where NSR may adversely impact investment in capacity and energy efficiency projects. These areas are examined further in this section in order to assess their nature and extent.

Refinery commenters observe that the refining industry differs considerably from the electric utility industry in several respects. For example, it is operating much closer to full capacity than the utility industry, and it is not transitioning from an economically regulated basis to a market basis. Even while operating at very high utilization rates, commenters noted that the industry must be able to respond rapidly to changes in raw material availability, market demands, and environmental requirements. API explained that, "[r]efiners are required by law to make adjustments to fuel specifications from one season to another, produce fuels meeting multiple specifications in various regions of the country, and reconfigure to refine cleaner burning low sulfur diesel and gasoline, all while being able to supply fuels to meet constantly changing customer demand."[55] API suggested that these requirements necessitate frequent and rapid responses that may involve changes to a refinery's facilities and processes. Moreover, they note that, to meet demand for petroleum products and avoid market disruptions that can lead to shortages and price volatility, the refining industry must be able to maintain the availability, reliability, and safety of its facilities. NPRA's comments noted, "Refining operations are continuous and complex. They depend on the simultaneous operation of many individual, but inter-related, pieces of equipment ("units"). A delay or inability to change or improve operations of a single unit can have a significant cumulative impact on the refinery's ability to produce the fuels that its customers, and the national economy, rely upon."[56] To meet increasing demand without major construction of new refining facilities, commenters believe that the industry must improve the efficiency of its existing facilities, and it must engage in what one industry commenter described as a "continuous incremental improvement in production capacity."[57] Finally, as noted in the Background Paper, and above, with no new refineries likely to be built in the near future, assessing the impact of NSR on existing sources is particularly critical.

As with utilities, refineries maintain that the exclusion for "routine maintenance repair and replacement" has been narrowed by EPA in recent years and undercuts their ability to respond quickly to market changes and raw material availability. In addition, refinery industry commenters expressed concern about the test used to determine whether a change results in an emissions increase at non-utility

---

[55] API Comments [II-D-134] at 1-2.
[56] *See* NPRA Comments [II-E-27]at 2.
[57] *See* BP America comments [II-D-307] at 2.

source categories (i.e., the "actual to potential" test). In the view of many refinery commenters, the NSR program has the effect of constraining the industry's ability to (1) expand domestic refining capacity, (2) increase the supply of cleaner burning fuels, and (3) enhance energy efficiency.[58] The commenters said that under the NSR program, numerous common activities at a refinery – whether required to respond to demand changes, to repair or replace a broken piece of equipment, to improve efficiency, to expand refining capacity, or even to respond to environmental requirements – are potentially subject to NSR permitting.[59] One industry commenter states that hundreds of such activities are undertaken each year at existing U.S. refineries.[60] According to commenters, the lengthy, costly, and uncertain nature of the current NSR permitting process discourages those activities to which it potentially applies, or at least introduces significant delays in and constraints on the ability of the operator to make the required changes in an efficient and timely manner.

Refining industry commenters also noted that, in their opinion, the NSR emissions increase test for non-utilities (the "actual-to-potential" comparison) presumes that virtually any activity at a refinery increases emissions within the meaning of NSR, even if the activity were, in fact, to result in decreased actual emissions.[61] Thus, these commenters stated that, of the activities undertaken at a given refinery, only those activities ultimately deemed to constitute "routine maintenance, repair or replacement" might avoid NSR. However, according to industry commenters, few activities beyond the most mundane maintenance activities that may be undertaken each year at a given facility would be deemed "routine" under the NSR regulations.[62] One commenter maintained that the NSR program would apply NSR to any change that: (a) results in an increase in capacity or capacity utilization of an existing process unit; or (b) increases the efficiency or lowers the unit operating costs; or (c) extends the useful life of that unit ..."[or (d)] increase[s] unit reliability."[63] According to industry, these are precisely the types of activities that U.S. refineries must constantly undertake to meet demand and minimize fuel supply disruptions and price volatility. Moreover, commenters suggest that the use of an actual-to-potential test encourages industry to maximize current actual emissions within permit limits, rather than providing incentives for emissions reductions.[64]

Industry commenters provided a list of activities that they reportedly undertake to maintain reliability, improve efficiency, and expand capacity that, in their view, are typically undertaken in the industry but, nevertheless, are potentially subject to NSR under the current program.[65] According to industry, the potential applicability of NSR, which they believe could encompass virtually any given project, tends to discourage operators from undertaking particular projects because NSR would add

[58] NPRA letter to Stephanie Daigle, EPA, 7/23/2001.

[59] *See* API Comments [II-D-134] at 2; ExxonMobil Comments [II-D-418] at 2; NPRA Comments [II-E-27] at 3.

[60] *See* Marathon Ashland Petroleum LLC (MAP) Comments [II-D-253] at 2.

[61] *See, e.g.*, ExxonMobil Comments [II-D-418] at 11(commenting that actual-to-potential test "fabricate[s] emission increases" where no increases actually occur).

[62] *See* ExxonMobil Comments [II-D-418] at 12; BP America Comments [II-D-307] at 2; MAP Comments [II-D-253] at 2.

[63] *See* BP America Comments [II-D-307] at 2.

[64] NPRA Comments [II-E-27] at Attachment 1, No. 1.

[65] See, e.g., NPRA comments [II-D-400] and API comments [II-D-134].

significant delays and costs.[66] Industry commenters observed that the EPA Background Paper's estimate for the length of time typically necessary to obtain an NSR permit did not include the time spent prior to submittal of a complete application. If such time is included, the length of the NSR permitting process in the experience of refinery commenters is at least 7 to 22 months, excluding any post-issuance appeals and challenges.[67] An industry commenter further predicted that, if the listed activities are viewed as non-routine, the refining industry, as well as other U.S. industries, would experience much longer lead times in obtaining NSR permits than already occur.[68]

Like utilities, refiners also raised the concern that there would be limited options for projects that are potentially subject to NSR.[69] They described three options. First, the operator could seek to obtain an NSR permit, accepting the delays, uncertainties, and potentially significant costs that commenters say are associated with such permits.[70] Alternatively, an operator could seek to "avoid" NSR by limiting emissions to past, actual levels through a minor NSR permit (a permit which, according to industry, can take 3-12 months to obtain), thus giving up refinery capacity and "deprive[ing] the source of the 'headspace' between actual and allowable emissions that is crucial to long-term operating flexibility and the ability to respond quickly to changes in demand."[71] A third option would be to simply cancel the project, and forego the projected benefit that was the reason for the project in the first place.

Overall, the comments submitted by refinery and other commenters during this review process emphasize their belief that by imposing significant costs and delays, the NSR program discourages investment in projects that are necessary to maintain the reliability of existing refineries, improve their efficiency, expand capacity, and respond flexibly to rapidly changing consumer demand for petroleum products. According to one commenter, what the industry most needs is certainty and flexibility in its efforts to meet both the energy needs of the Nation and environmental requirements.[72]

In contrast, NRDC's comments suggest that poor return on investment is more important than environmental considerations (of which NSR is only a small part, and is not specifically named by sources examined in the EPA Background Paper) in any decisions not to invest in new capacity.[73] They point to information presented in the Background Paper showing that, in recent years, there has been significant investment in refinery capacity at existing sources.

As discussed above for utilities, the EPA notes that for refineries there are also differences of opinion amongst the commenters about the scope of the routine maintenance exclusion and the resulting impacts. In determining whether an activity is "routine" for purposes of being excluded from NSR, EPA consistently has taken a case-by-case approach, weighing the nature, extent, purpose, frequency and cost of the work, as well as other relevant factors. However, EPA acknowledges, as it did for utilities,

---

[66] NPRA Comments [II-E-27]at 2.

[67] *See* API comments [II-D-134] at 8.

[68] *See* ExxonMobil Comments [II-D-418] at 16.

[69] *See* BP America Comments [II-D-307] at 2.

[70] *See id.*; *see also* ExxonMobil Comments [II-D-418] at 18 (noting both the cost and scheduling impacts of NSR on project economics).

[71] *See* BP America Comments [II-D-307] at 2-3.

[72] *See* API Comments [II-D-134] at 2.

[73] NRDC comments [II-D-267]at 5.

that the comments report significant uncertainty about the scope of the "routine" exemption. Such uncertainty can result in the delay or cancellation of projects. Changes to the NSR program that add to the clarity and certainty of the scope of the routine maintenance exclusion will improve the process by reducing the unintended consequences of discouraging worthwhile projects that are in fact outside the scope of NSR.

A key difference between utilities and refineries is the fact that refineries use the "actual-to-potential test" for determining NSR applicability, while utilities generally do not. The EPA has reviewed a number of examples where projects could have provided capacity increases or energy efficiency improvements, and likely could have done so without increasing actual emissions, and in some cases the projects appear likely to decrease actual emissions. Such projects, if they occur at units operating below capacity, could trigger NSR or, at least, trigger a need to cap the units below capacity or install pollution controls to avoid NSR. Again, the determination of whether a change results in an emissions increase is a case-by-case determination, but the EPA believes that the commenters' examples make a credible case that some capacity or efficiency projects that do not increase *actual* emissions are not undertaken because they trigger NSR under the actual-to-potential test. Although the information is mostly anecdotal in nature, the EPA believes that the information presented is based on real world experience, and makes a credible case that some projects are not going forward in part because of NSR. The EPA believes that this results in lost refining capacity, or foregone opportunities to increase capacity without increasing emissions.

IV. Impact on Industries Other than Electric Utilities and Petroleum Refineries

In addition to the information supplied to EPA by utility and refinery commenters, the Agency received numerous comments from other industries regarding the NSR program's impact on energy use, efficiency, and capacity. These comments came principally from a variety of industry associations and coalitions of manufacturers representing the automobile, aerospace, chemical, electronics, food, aluminum and steel, packaging, paper, printing, pharmaceutical, and other manufacturing sectors. Like the utility and refining industries, these commenters were primarily concerned with the current application of the NSR program to existing sources. They noted many anecdotal instances where projects would have reduced energy demand and/or increased energy efficiency, but were abandoned because of NSR permitting delays and/or costs associated with the retrofit of existing equipment with the BACT or LAER emissions controls mandated by NSR rules. Other commenters presented similar examples of pollution control and pollution prevention projects abandoned because of potential NSR applicability. According to the commenters, the cancellation of projects that would have improved energy efficiency or decreased pollution means that NSR is having an adverse impact on investment in both energy efficiency and environmental protection.

Among the general concerns voiced by commenters in addition to pollution control costs were claims that (1) the NSR program is complex and gives rise to uncertainty and associated delays, (2) it hinders flexibility for industry to quickly make needed changes, and (3) that it results in the loss of production capacity where NSR is triggered based on the application of the actual-to-potential test, even if emissions will not actually increase. Furthermore, commenters argued that if a source wants to avoid NSR, it faces the undesirable outcome of accepting new emissions limits in the NSR permit that, according to commenters, effectively reduce a plant or unit's productive capacity.[74]

A. NSR Applicability

1. *Routine Maintenance, Repair & Replacement*

As with utilities and refineries, many commenters from other industry sectors focused on the NSR "routine maintenance, repair and replacement" exclusion. Like the industries discussed above, they believe that EPA has narrowed the exclusion in recent years. Thus, they stated this was the day-to-day largest problem in maintaining the availability, reliability, and safety of production equipment.[75] In particular, commenters asserted that projects involving repair or replacement components incorporating "state-of-the-art" improvements in materials or design may be subject to NSR since they may not qualify as routine maintenance, or may result in more efficient utilization of fuel and/or raw materials that may potentially increase a facility's emissions. For instance, at one plant, a company states that it elected not to replace spray nozzles in a process dryer, even though it determined that significant energy savings could result, because it concluded that the new Teflon coated nozzles would not be equivalent parts and, therefore, the project would not be exempt from NSR as routine. According to the commenter, the new nozzles would have resolved the repeated need to replace the existing equipment, and may have provided a safer and more reliable operating environment.[76]

Similarly, commenters complained that NSR application discouraged engineering design innovations that provide better quality and control assurances during sometimes-dangerous production processes. One example, provided by the chemical industry, was the installation of a temperature regulating system on a thermal jacket around a dryer that is equipped with a heated jacket that uses a temperature control system in the jacket. The temperature control system works by regulating the flow of steam or hot liquids similar to radiator fluids in the jacket that surrounds the dryer. The current system uses an older design and is relatively ineffective because of the system's wide temperature variation, which causes risks of explosion and lengthens the drying process time. Both problems could be eliminated with the installation of a temperature regulating system, which would also reduce energy demands on the process by 20%. Although work is often performed on the jacket regulating system, the company suggested that it did not go forward with the change because work on the temperature regulating system, utilizing a unique new system, would not be considered "routine."[77]

It was also suggested that application of the NSR program impeded the ability of companies to undertake projects to ensure the reliability of their equipment that might also result in significant energy efficiency gains. Commenters presented a number of examples of such projects, including examples

---

[74] *See, e.g.,* Comments of NEDA/CARP [II-D-272] at 9-10.

[75] *See, e.g.*, FPA Comments [II-D-271] at 2-3.

[76] NEDA/CARP Comments [II-D-272] Attachment A, Example # 1.

[77] NEDA/CARP Comments [II-D-272] Attachment A, Example # 4. According to this example, only 2 tons per year of regulated emissions would have resulted from the change, but potential emissions could have increased over 100 TPY of VOC because operation of an incinerator with a 98% control efficiency voluntarily installed by the company is not considered to be "federally enforceable."

from the chemical, packaging, aluminum and general manufacturing sectors. One illustration from the American Forest and Paper Association described replacement of outdated analog controllers at a series of six batch digesters. The original controllers were no longer manufactured, although new digital controllers, costing approximately $50,000, are capable of receiving inputs from the digester vessel temperature, pressure and chemical/steam flow. The new controllers would have more precisely filled and pressurized digesters with chips, chemicals and steam (whereas the old controllers added materials in timed sequence), thus bringing a batch digester on line faster. However, the source determined that under the NSR program this project would not be considered to be routine because, although repairs to the analog system might have been frequent at the company involved, replacement of the system with a digitalized, computerized system would not qualify as "routine."[78]

As with utilities and refineries, EPA notes that there are widely differing views on the scope of the routine maintenance exclusion on other industries. As before, we therefore conclude that concern about the scope of the routine maintenance exclusion is having an adverse impact for industries outside the energy sector. It also is credible to conclude that projects have been discouraged that might have been economically and/or environmentally beneficial without increasing actual emissions. Changes to the NSR program that add to the clarity and certainty of the scope of the routine maintenance exclusion will improve the process by reducing the unintended consequences of discouraging worthwhile projects that are in fact outside the scope of NSR.

2. *Pollution Prevention Projects*

Another series of examples provided by commenters from the manufacturing sector involved pollution prevention projects, many with significant energy savings potential. Pollution prevention projects at manufacturing facilities may qualify for exemption under the NSR program. This determination is made on a case-by-case basis under EPA's 1994 guidance which addresses pollution control projects and NSR applicability. Although this guidance was intended to create incentives for industry to undertake such projects, some comments suggested that it might actually discourage such projects. One example comes from the chemical industry. In that case, a chemical facility considered installation of a new, more efficient CFC refrigeration system. Completion of this project, according to the commenter, would have resulted in decreased CFC emissions and less electricity demand, reducing overall emissions from the facility's power generating plant. However, this project would not have qualified for the pollution control project exclusion because the primary purpose of the project was not to reduce emissions. Therefore, because the project otherwise would have triggered NSR, the company elected not to undertake it. [79]

In a second example, an aerospace company suggested that it was unable to avoid NSR, using EPA's 1994 pollution control project policy, because the purpose of a particular project was to improve energy efficiency, although significant pollution control benefits would also have resulted. The company had proposed to speed up its manufacturing process (for parts and subassemblies) by using a new adhesive that would dry (or cure) faster. The company stated that the project would have resulted in pollution prevention both because the new adhesive had a lower volatile organic compound (VOC) content than the one in use and because more parts could be processed in less time, consuming less

[78] AFPA Comments [II-E-15], Tab 3, Case in Point # 4.
[79] Comments of American Chemistry Council [II-D-416] example 1.

energy overall. However, this project could not qualify for the pollution control project exclusion because its purpose was to improve efficiency, rather than to abate pollution and because the new adhesive system would have increased the utilization of production equipment at the plant. Because the project otherwise would have triggered NSR applicability, the company declined to make the change.[80]

EPA believes that these examples indicate that NSR is having an adverse impact on some pollution control and prevention projects.

B. Energy Efficiency

The Agency also received a number of industry comments explaining the NSR program's effect on energy efficiency and demand. These comments suggest that the delays and costs associated with NSR have discouraged the adoption or implementation of various energy conservation and efficiency measures. Examples provided by commenters included efforts to conserve fuel and programs that will result in energy demand reductions at major industrial plants. The commenters allege that, in many cases, the projects would ultimately reduce actual emissions, but nonetheless trigger NSR under the actual-to-potential test.

For instance, NSR was cited as a principal reason for not undertaking energy efficiency projects for the installation of heat exchangers and overfire air by various manufacturing sectors including the electronics and appliance industries, plastics, and paper industries. Heat exchangers recover heat from boiler flue gas streams to heat water used in the system's deaerator units. By preheating the water used in the deaerator units, the heat exchanger reduces the steam needed to run the deaerators. This increases the overall efficiency of the boiler house and reduces fuel usage. It also reduces annual boiler emissions. At a plastics plant, a commenter pointed out that installation of a heat exchanger would be expected to reduce natural gas consumption by 7.5 percent, NO_X emissions by 7.5 percent, SO_2 emissions by 5.8 percent and carbon monoxide (CO) emissions by 7.6 percent, particulate matter (PM) emissions by 9 percent, and VOC emissions by 9.3 percent. The project achieves these benefits through pollution prevention rather than add-on controls.[81] In this case, the industry applicant sought exclusion from NSR applicability under the pollution control project exclusion. However, this project did not qualify as a pollution control project because its primary purpose was not pollution control or prevention. Moreover, because the boilers required back-up firing with oil during the winter to ensure operation, the "actual to potential" emission test would have caused the project to trigger NSR. To avoid the installation of new controls that would be mandated as the result of NSR applicability, the source states that it is considering burning more fuel oil over the next two years to increase base level of emissions (actual emissions).

Another example from a boiler at a pulp and paper mill illustrates a similar problem. According to the comment, the mill's industrial boiler currently experiences extensive, internal erosion as a result of the carryover of solids such as sand and wire from the burning of tire-derived fuel, and burned bark particles, which have led to decreased boiler efficiency. As a result, the mill proposed to install a new overfire air system to allow for more complete combustion of the bark fuel. By getting more heating value from the same amount of bark burned, less natural gas would be required to provide

---

[80] NEDA/CARP Comments [II-D-272] Attachment A, Example # 14.
[81] NEDA/CARP Comments [II-D-272] Attachment A, Example # 15.

supplemental heat at an annual natural gas savings of about $1 million (in July, 2001 dollars). According to the comment, future actual emissions of NO_X, CO and VOCs would decrease after completion of this project. However, because the boiler is currently operating below its rated capacity, the potential emissions after completion of the project would increase over past actual emissions, triggering NSR. The commenter estimates that the cost of NSR controls would be $17 million.[82] At the time this project was under consideration, the relevant company estimated that the annual savings in natural gas usage equated to roughly 200 million cubic feet of natural gas. This amount of gas has a heating value of approximately 0.2 trillion Btu.

The Department of Energy has estimated that overfire systems could be installed on 20 percent of the 200 coal fired boilers in the industry, resulting in 680,000 MW-hr in energy savings annually. Additional energy savings reportedly are possible if overfire air provides similar benefits in wood-fired systems. Potential reductions in NO_X, $S0_2$, CO, PM, VOCs and other pollutants such as mercury would accompany such energy savings.

Commenters also expressed a need for operational flexibility, and asserted that NSR delays can limit such flexibility, with the result that if changes are projected to trigger NSR, even changes that improve energy efficiency, they are no longer economically viable. Because some industries must make rapid changes in their product lines it is very difficult for them to manage NSR compliance. One such example was provided by the flexible packaging industry. In that case, the industry has been moving steadily toward the replacement of solvent-based inks and coatings with water-based inks and coatings in the production of packaging for foods, drugs, cosmetics, and other household goods. However, certain product orders reportedly require, from time-to-time, solvent-based inks or coatings, and these operations are required to operate large thermal oxidizers by their permits. In addition many of the low VOC coatings contain materials that can poison a thermal oxidizer's catalyst. Therefore, the plant asked its permitting agency to change its permit to run the oxidizer only when it runs VOC-based coatings.[83]

In this instance, the operator calculated that the change could save approximately 15,000 cubic feet of gas and 650 kWh of electricity each day. However, the commenter felt that the change would probably be a change in the plant's method of operation, triggering NSR, even though actual emissions were expected to be reduced by the change. Because of the nature of its operations, involving product batches sometimes constituting only hours of a day's run, the company did not feel it could accept limits on its hours of operation. Therefore, the project, which according to the commenter was conceived as a way to create large energy savings, did not go forward.[84]

A number of commenters claimed to have abandoned energy conservation projects because they determined that NSR would apply and make the project cost-prohibitive. For instance, at one commenter's automobile assembly plant, the company wanted to eliminate one shift of a two-shift operation due to downward market fluctuations. This would have resulted in a reduction of roughly 30% (0.4 billion cubic feet) of annual natural gas usage in the plant's boilers, ovens, thermal oxidizers and other fuel combustion equipment at a cost savings of greater than $2 million dollars annually. In

---

[82] AFPA Comments [II-E-15], Tab 3, Case in Point # 1.
[83] FPA Comments [II-D-271] at 6-7.
[84] *Id.*

addition, electrical power consumption would have been reduced by roughly 10%, at a cost savings of greater than $700,000 annually. In order to accommodate this change, however, the facility needed to install certain pieces of equipment, consisting mostly of assembly motors to increase the production capability of a single shift by two automobiles per hour. According to the comment, because of the actual-to-potential test, and the source's reluctance to take a cap limiting it to one-shift operation, the project would have triggered NSR and the project would no longer have been economically viable.[85]

Overall, the comments received from industries other than utilities and refineries also provide additional evidence suggesting that the current NSR program is having an adverse impact on energy efficiency by discouraging projects that may improve energy efficiency, or may increase capacity and reliability without actually increasing pollutant emissions. In some cases it may even be discouraging projects that decrease emissions, because of the "actual-to-potential" test used for these industries.

V. Impact on Environmental Protection

Overall, EPA believes that preventing emissions of pollutants covered by NSR does result in significant environmental and public health benefits. Attempting to specifically quantify the NSR program's contribution to these benefits is very difficult because of the variety of Clean Air Act programs that address these pollutants and because there is no tracking by any government agency of the reductions in emissions that sources make due to the NSR program. Moreover, EPA recognizes that measuring risk reduction benefits associated with any given reduction in emissions requires complex risk assessments that would, in turn, require more specific information than has been gathered in the context of this review.

We note that NSR is implemented in the context of several other significant Clean Air Act programs. Available information indicates that these other programs result in substantial emissions reductions. For example, the Title IV Acid Rain Program has reduced SO_2 emissions from the electric utility industry by more than 7 million tons per year. The Tier 2 motor vehicle emissions standards and gasoline sulfur control requirements will ultimately achieve NO_x reductions of 2.8 million tons per year. Standards for highway heavy-duty vehicles and engines will reduce NO_x emissions by 2.6 million tons per year. Standards for non-road diesel engines are anticipated to reduce NO_x emissions by about 1.5 million tons per year. The NO_x "SIP Call" will reduce NO_x emissions by over 1 million tons per year. Altogether, these and other similar programs achieve emissions reductions that far exceed those attributable to the NSR program. Moreover, most of these other programs are much more efficient, streamlined, and simple than NSR because they do not entail the same resource-intensive, case-by-case review that is required under NSR.

It would be very difficult to estimate or quantify the benefits of the NSR program. However, EPA believes that the inability to make exact estimates does not mean that these benefits are insignificant or nonexistent. Notably, industry concerns about NSR focused almost exclusively on problems associated with applying the program to existing sources. These comments illustrated a potential dichotomy in that the benefits of the NSR program are largely attributable to new sources while the existing sources reportedly are more burdened by the program.

---

[85] NEDA/CARP Comments [II-D-272] Attachment A, Example # 12.

Electric utilities and petroleum refineries are significant sources of air emissions. The major regulated air pollutants emitted from power plants are SO_2, NO_X, PM, and mercury. Refineries primarily emit SO_2 and NO_X, as well as VOCs. Based on 2000 emissions, the electric utility industry is the single largest source of SO_2 emissions and the second largest source of NO_X emissions (on road mobile sources are the largest). In 2000, the electric utility industry emitted 11.2 million tons of SO_2, 5.1 million tons of NO_X, and 302,000 tons of PM. In 1999, refineries emitted 479,000 tons of SO_2, 299,000 tons of NO_X and 161,200 of volatile organic compounds. Emissions of these pollutants from all sectors in 1999 totaled 18.9 million tons SO_2, 25.4 million tons NO_X, 18.1 million tons VOC, and 23.7 million tons PM.

There is a significant body of scientific literature linking air pollution to several health effects. These include: premature mortality, chronic asthma and increased asthma attacks, chronic and acute bronchitis, other chronic respiratory diseases and damage, increased airway responsiveness to stimuli, inflammation in the lung, respiratory cell damage, premature aging of the lungs, increased susceptibility to respiratory infection, decreased lung function, developmental effects, infant mortality, low birth weight, cancer, decreased time to onset of angina, other cardiovascular effects. Additional effects include decreased worker productivity; increased emergency room visits for respiratory and cardiovascular effects, and more hospital admissions for respiratory and cardiac diseases.[86]

Potential effects beyond human health effects include direct damage to plants and forests, decreased yields for crops and forest products, damage to ecosystem functions, decreased visibility, corrosion and soiling of buildings and monuments, eutrophication (i.e., explosive algae growth leading to a depletion of oxygen in the water), acidic deposition and acidification of water bodies, and impacts on recreational demand from damaged aesthetics and decreased visibility.

The EPA Background Paper provided some preliminary estimates of the amount of emissions prevented by the NSR program for all industries in "clean" areas (e.g., emissions that would have otherwise occurred from construction/modification). The NSR program in such clean areas is known as the PSD program. The Paper stated that for the period 1997 through 1999, new or modified source compliance with PSD for all industries prevented approximately 1.4 million tons of air pollution from being emitted per year. The vast majority of these reductions are attributable to the application of NSR

---

[86]In response to public requests for more such information, the Agency has added to the docket some general benefits information about reductions in emissions of pollutants likely to be impacted by the NSR regulations. (A) U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Regulatory Impact Analysis for the NO_X SIP call, FIP, and Section 126 Petitions: Volume 1, Cost and Economic Impacts. September, 1998. Located on the Internet at www.epa.gov/ttn/oarpg/otag/sipriav1.zip; (B) U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Regulatory Impact Analysis for the NO_X SIP call, FIP, and Section 126 Petitions: Volume 2, Health and Welfare Benefits. December, 1998. Located on the Internet at www.epa.gov/ttn/oarpg/otag/sipriav2.zip; (C) U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Regulatory Impact Analysis for the Final Regional Haze Rule. April, 1999. Located on the Internet at www.epa.gov/ttn/oarpg/t1/reports/riaes.pdf; and (D) U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Regulatory Impact Analysis for the Final Section 126 Petition Rule. December, 1999. Located on the Internet at www.epa.gov/ttn/oarpg/t1/reports/126fn0.pdf.

to new gas fired electric generating units. The Background Paper also reported that this number underestimates total emission reductions because it does not include estimates of emissions prevented in nonattainment areas through nonattainment NSR permitting requirements during that same time period.

Several commenters reiterated this position and noted that as a general rule these reductions would be greater because the control requirements are more stringent and the offset requirements essentially result in a net emissions decrease. Although EPA agrees that there are additional emission reductions that result from compliance with the offsets requirements of nonattainment NSR program, at this time the Agency does not have information quantifying those emissions reductions. Finally, other commenters noted that the EPA Background Paper failed to address the emission reductions of SO_2 and NO_X that occur as a result of sources reducing their emissions so as to avoid the applicability of NSR altogether. On the other hand, since SO_2 emissions from the utility industry are capped by the Title IV acid rain program, NSR does not produce overall net reduction in SO_2 emissions from the industry. Similarly, in nonattainment areas, Title I effectively caps emissions of the nonattainment pollutant. To a degree, the same is true for seasonally or geographically limited cap and trade programs, such as the "NO_X SIP call." Furthermore, as noted below, industry commenters note that these estimates of emission reductions attributed to NSR do not account for foregone emissions reductions that they allege would have occurred in the absence of NSR's disincentives to proceed with projects that increase efficiency.[87]

A large number of commenters, primarily citizens and environmental groups, expressed strong support for the benefits that derive from reducing emissions from these industrial sectors, either by installing pollution reduction controls on new sources as they are built, or on existing sources as they are modified. Many groups argued that the public health threat from the air emissions of power plants and refineries is urgent and further reductions are needed. Noting environmental justice concerns, one commenter stated that 80 percent of the refineries in the Texas oil refinery communities are either populated by minority citizens or contain significant minority representation and reported that approximately three million minority citizens live in these Texas communities.

The EPA Background Paper also presented previous estimates of the health benefits per ton of pollutant reduced for SO_2 and NO_X emissions based on a study of emissions at utilities. The work cited in the EPA Background Paper is based on the benefits of reducing premature mortality associated with long-term exposure to PM. However, many citizen and environmental group commenters requested a more detailed discussion of additional health benefits like the avoidance of reduced lung function, asthma attacks, lost work days and premature death, which have been linked to these air pollutants. For example, one commenter representing 43 environmental groups cited a study by Abt Associates presenting their estimate that national power plant emissions accounted for more than 6,000 asthma attacks, 30,000 premature deaths, and 5 million lost work days per year, noting that elderly people with respiratory disease and children are at the greatest risk.

Commenters requested that EPA present information on the benefits due to avoided emissions of other pollutants, including pollutants that are reduced collaterally when criteria pollutants are

[87] First Energy Corporation testimony on NSR, 7/10/2001, stated that current interpretations of NSR would have prevented projects now resulting in a reduction of 40,000 TPY of SO_2 and NO_X emissions.

controlled (e.g., mercury). One commenter notes that EPA documents identify coal-fired power plants as the largest industrial emitters of mercury, another pollutant with well-documented health and environmental effects. Thus, without addressing the benefits that derive from reductions of these pollutants as well, several commenters argue that the EPA Background Paper significantly underestimates public health and environmental benefits of NSR.

Many commenters also mentioned numerous other benefits that result from lower emissions from power plants and refineries. They presented information about impacts primarily of power plant emissions on the environment, particularly in National Parks. For example, several groups provided information regarding the adverse impact of power plant emissions in particular on visibility in National Parks. Some commenters also note that ground level ozone (smog) not only impacts vegetation (more than 50 species of plants and trees allegedly harmed by ozone), but also the health of visitors to National Parks. Additionally, commenters note the impact of SO_2 and NO_X emissions on the formation of acid rain and its impact on ecosystems (e.g., red spruce decline, fish killed). Finally, many commenters were also concerned about CO_2 emissions and their potential to affect climate, and believed that NSR plays a role in preventing these emissions as well. Commenters urged EPA to discuss the benefits generally of reduced emissions in all these areas more explicitly, and quantify them as they relate to the NSR program.

In addition, several commenters noted that in nonattainment areas, a source's failure to reduce emissions through NSR places the burden on other sources to reduce emissions. In other words, because the State has to reduce emissions somewhere in order to attain air quality standards, it will target other sources (e.g., construction activities), or even consumers in order to create those reductions. Even in attainment areas, compliance with PSD requirements can help maintain the area's ability to continue to grow.

Some state and local governments supported the role NSR plays in preventing emissions from new and modified sources.[88] They believe, based on their experience, that without NSR, emissions from new and modified sources would severely interfere with their efforts to attain and maintain air quality standards. While there are several important programs that reduce emissions from existing sources, they felt NSR was a critical complementary program because it minimized emissions from new sources.

Some commenters also expressed support for the technology-forcing aspect of the NSR program, arguing that it is the only CAA program that automatically mirrors improvements in control technology over time, and therefore encourages continued development of cleaner technology. Commenters urged EPA to estimate the benefits of this effect as well.

Industry commenters felt that the current NSR program actually acts as a barrier to improved environmental protection in certain instances. Although NSR is only triggered when emissions increase, these commenters argued that the way EPA calculates an increase in emissions can actually have the effect of subjecting a project to NSR that would decrease actual emissions. Because of the delay and costs associated with applying NSR to a project, NSR renders these environmentally beneficial projects uneconomical, and they may be rejected. Similarly, again because of the way that NSR

[88] *See, e.g.* STAPPA/ALAPCO comments.

calculates emissions increases, several industry commenters noted an incentive to keep actual emissions high because the closer actual emissions are to a source's maximum capacity to emit, the less likely it is to trigger NSR.

VI. Conclusion

Based upon the information examined during this review of the NSR program, there appears to be little incremental impact of the program on the construction of new electricity generation and refinery facilities but a more dramatic impact on investment in utility and refinery generating capacity and energy efficiency at existing utility and refinery plants. Looking at industry as a whole, there also is clear evidence of NSR's benefits for environmental protection.

With respect to environmental protection, the EPA finds that NSR is not designed to play the primary role in reducing emissions from existing sources. In fact, for pollutants covered by a national cap and trade program (such as the Title IV acid rain program), the NSR program does not necessarily produce any overall emissions reductions. Furthermore, EPA believes that in particular industry sectors – especially the utility sector – the benefits currently attributed to NSR could be achieved much more efficiently and at much lower cost through the implementation of a multi-pollutant national cap and trade program.

Nevertheless, the NSR program plays a role in attainment and maintenance of the NAAQS, particularly with regard to new sources. It helps ensure that as industry continues to grow and expand, air quality is managed appropriately (i.e., by helping assure that clean areas do not worsen and that dirty areas get cleaner). It also helps to protect sensitive areas like national parks and wilderness areas, and promotes new and more effective pollution controls. As described in this report, and thoroughly detailed in the comments and other references provided, NSR also provides health and ecological benefits.

With respect to new facilities, the NSR program's principal impacts are in the form of delays and additional costs, but there is little evidence that these delays and costs are preventing new source construction in the utility industry. Indeed there is substantial evidence that significant new generating capacity is being brought online within normal time frames for planning such projects.

With respect to the maintenance and operation of existing utility generation capacity, there is more evidence of adverse impacts from NSR. Credible examples were presented of cases in which uncertainty about the exemption for routine activities has resulted in delay or cancellation of projects which sources say are done for the purposes of maintaining and improving the reliability, efficiency and safety of existing energy capacity.[89] Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution.

There appeared to be little impact of NSR on planning for new greenfield refineries, because new refineries are not being built for economic and environmental reasons unrelated to NSR. For existing refineries, the points raised above about the routine maintenance exclusion apply equally well to refineries as they do for utilities – the EPA observed that commenters expressed uncertainty about the application of the exclusion to any particular project. Existing refineries, however, face an additional issue: the actual-to-potential emissions test. The EPA found credible examples of projects at existing units that would have provided needed capacity or efficiency improvements and would likely not have increased – and in some cases may have decreased – actual emissions. Due to the actual-to-potential test, such projects, if they occur at units operating below capacity, could trigger NSR unless the company committed to continue operating the units below capacity or installed pollution controls. The EPA believes that this potentially results in lost refining capacity, or foregone opportunities to increase capacity without increasing emissions, which could contribute to price volatility and shortages in fuel supply.[90]

With respect to energy efficiency, the EPA recognizes that the NSR program applies to certain projects that have the effect of increasing efficiency (e.g., projects that increase electricity output for a given fuel input). The ordinary costs and permitting times associated with NSR may, in the EPA's judgment, result in the delay or cancellation of certain projects that could improve energy efficiency. EPA encourages energy efficiency improvements wherever feasible. However, the EPA notes that some changes that improve energy efficiency also can result in significant emissions increases that have adverse air quality impacts that must be reviewed, even though the proposed project could reduce regional or national emissions. Thus, of the universe of possible efficiency improvements, the appropriate focus of the NSR program is on those that are non-routine and that significantly increase emissions. At non-utility source categories, the "actual to potential" emissions test can discourage efficiency improvement projects even where there would not be an increase in actual emissions. It is clear that some of these efficiency improvements can still go forward (by going through NSR or taking steps to avoid NSR); however, it also is clear that others are in fact canceled due to the costs and delays associated with NSR.

As noted at the beginning of this report, representatives of industry, state and local agencies, and environmental groups have worked with EPA for over a decade on developing improvements to

---

[89] Very few commenters provided sufficiently detailed examples for EPA to make definitive judgements as to whether the given projects would have been considered nonroutine or ultimately triggered NSR. As a result, EPA cannot quantify the number of projects affected or the corresponding impacts on capacity, reliability, efficiency, safety, or other relevant factors. Based on the information presented, it appears unlikely that many of the examples discussed would trigger NSR either because they would qualify for the routine exclusion or they would not increase emissions significantly. Nevertheless, the anecdotal information was sufficient to support our conclusions with regard to the overall impact of the NSR program.

[90] The EPA notes that its conclusions for refiners are equally valid for the numerous non-utility/non-refinery sources that commented during the review.

the NSR program. Our findings in this report ratify a longstanding and broadly-held belief that parts of the NSR program can and should be improved. For example, we conclude above that changes to NSR that add to the clarity and certainty of the scope of the routine maintenance exclusion will improve the program by reducing the unintended consequences of discouraging worthwhile projects that are in fact outside the scope of NSR. For these reasons, EPA is recommending a number of changes to the NSR program that will address the concerns raised during this NSR review as well as many other concerns presented to EPA about NSR over the past decade.

Docket A-2001-19
Document II-A-01

NSR 90-Day Review Background Paper

June 22, 2001

Table of Contents

Introduction 1
I. Overview of the NSR Program 2
The Permit Application Process 5
II. Electric Power Industry 9
1. Historical NSR Permitting Data 9
2. Factors Affecting Investment in New Capacity 10
3. Trends in Electric Capacity and Utilization 12
4. Data on Costs of Pollution Controls 18
5. NSR Impacts on Capacity Additions 21
6. NSR Impacts on Energy Efficiency Improvements 28
III. Petroleum Refining Industry 29
1. Historical NSR Permitting Data 29
2. Factors Affecting Investment in New Capacity 31
3. Trends in Capacity and Utilization 33
4. Data on Costs of Pollution Controls 40
5. Data on Refinery Profitability 43
6. NSR Impacts on Capacity Additions 43
APPENDIX A 47

List of Figures

Figure 1: Average Permitting Time for PSD Permits 7
Figure 2: Estimated Emissions Avoided Due to PSD BACT Permitting (1997-1999)....................8
Figure 3: Utility and Non-Utility Capacity in 1999 12
Figure 4: Total U.S. Electric Capacity (1980 – 1999)....................13
Figure 5: Annual Net Capacity Additions (1973 – 1999) 14
Figure 6: Reserve Margins (Percent Capacity Over Peak Demand (1980 – 1997)....................15
Figure 7: Cumulative Capacity Additions by Energy Source (1987 – 1999)....................16
Figure 8: Cumulative Capacity Additions and Retirements of Coal-Fired Capacity 16
Figure 9: Availability, Utilization, and Efficiency for Coal-Fired Plants (1989 – 1999) 17
Figure 10: Total Capacity (GW) – Utilities and Non-Utilities (1989 – 1999) 18
Figure 11: ERC Bid and Offer Prices for Specific Criteria Pollutants (May 2001) 20
Figure 12: Summary of Selected Planned Development Activities Based on Public Statements....................26
Figure 13: Number and Capacity of Total U.S. Operating Refineries (1986 – 1999) 33
Figure 14: Total U.S. Atmospheric Distillation Capacity and Daily Avery Supply and Demand of Finished Products (1986 to Present) 35
Figure 15: Atmospheric Distillation Capacity for Total U.S. Refineries and Surviving 149 Refineries (1986 to Present)....................36
Figure 16: Total U.S. Refinery Utilization (1986 to Present) 37
Figure 17: Downstream Processes Capacity for 149 Refineries in Continuous Operation from 1986 to Present....................38
Figure 18: Atmospheric Distillation Capacity for Attainment and Nonattainment Regions for 149 Refineries in Continuous Operation from 1986 to Present 39
Figure 19: Refining Capital Expenditures and Pollution-Related Capital Expenditures 41
Figure 20: Historical U.S. Refining and Market Investments 42
Figure 21: U.S. Refined Products Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies (1990 – 1999)....................43

Introduction

In the National Energy Policy Report issued in May 2001, the National Energy Policy Development (NEPD) Group recommended that the Administrator of the Environmental Protection Agency (EPA), in consultation with the Secretary of Energy and other Federal agencies, examine the New Source Review (NSR) regulations, including administrative interpretations and implementation, and report to the President within 90 days on the impact of NSR on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection[1].

This document is the first step in fulfilling that responsibility. The purpose of this document is (1) to provide background on the NSR program and its implementation; (2) to provide an introduction to some of the information EPA is developing for the final report; and (3) to request comment upon the information in this document and additional information needed for the review. The data contained in this background document is based largely on a search of publicly available information. EPA recognizes that there are additional important data not readily available that would be helpful in undertaking the examination directed by the NEPD. Specifically, some of the additional information that would be useful includes: (1) the amount of time typically spent in pre-permit application activities; (2) any impact of NSR requirements on investment in expansions of or new utility and refinery generation capacity; (3) the significance of the cost of offsets in nonattainment areas related to the annualized cost of control; (4) the impact, if any, of minor NSR on investment in new utility and refinery generation capacity and energy efficiency; and (5) information on the impact of NSR on energy production and efficiency in other industries.

EPA also recognizes that much of the data in this report is related to the impact of the NSR program on the construction of new facilities. This does not reflect a lack of interest in existing facilities, but rather a lack of publicly available data regarding the impact of the NSR program on such facilities. The Agency is requesting data on how the NSR program may affect existing sources, including data on the extent to which the program has affected the ability of existing sources (1) to undertake pollution prevention or energy efficiency projects; (2) to switch to less polluting fuels or raw materials; (3) to maintain the reliability of production facilities; and (4) to effectively utilize and improve existing capacity. The public is invited to comment on the information contained in this document, and to provide EPA with any additional information that should be considered for inclusion in the final report that will be sent to the President in August. That final report, which will contain conclusions and recommendations, will be based in part on the information in this paper, as well as data and analysis both provided by the public and developed by EPA and its consulting agencies.

EPA's review of NSR will include not only examining how NSR is operating now with respect to the issues raised but also what kind of changes to the program might be desirable in light of these issues. The changes may include different administrative approaches, changes to rules, and legislative changes. EPA is seeking input on a broad range of potential approaches, not limited to pending regulatory revisions to the NSR program, nor to the various alternative approaches presented by the variety of stakeholder interest groups in EPA-led public forums over the past few years. Public input on alternatives, and their relative environmental impact, costs, and impact on power plant and refinery capacity and efficiency will be considered in the review.

---

[1] The National Energy Policy Report included a number of related recommendations which might influence the recommendations in the final report on NSR. Both the recommendation for this 90-day study and the related recommendations are included in Appendix A of this paper.

Section I of this document provides an overview of the NSR program. Sections II and III present basic data on the electric generation and refining industries, respectively, including any data specific to the impacts of NSR on investment in new capacity, energy efficiency, and the environment.

I. Overview of the NSR Program

Introduction

The basic requirements of the NSR program are established in parts C and D of Title I of the Clean Air Act. The purpose of the program is to protect public health and welfare, as well as national parks and wilderness areas, even as new sources are built and existing sources expand. Specifically, its purpose is to ensure that (1) air quality does not worsen where the air is currently unhealthy to breathe, and (2) air quality is not significantly degraded where the air is currently clean. The fundamental philosophy underlying NSR is that a source should install modern pollution control equipment when it is built (for new sources) or when it makes a major modification that increases emissions significantly (for existing sources). Congress believed incorporating pollution controls into the design and construction when new units are built or when old ones are modified significantly is generally the most efficient way of controlling pollution from major sources.

NSR requires a source to obtain a permit and undertake other obligations prior to construction to control its emissions of air pollution. However, NSR only applies if the construction project results in the potential to emit air pollution in excess of certain threshold levels established in the NSR regulations. For a new source, NSR is triggered only if the potential emissions qualify as major. For an existing major source making a modification, NSR is triggered only if the modification will result in a significant increase in emissions[2].

In general, the NSR program is administered by state and local air pollution permitting authorities. Each state or local permitting authority is required to incorporate basic NSR program requirements into its state implementation plan (SIP), which is the state's plan to ensure progress toward, or maintenance of, attainment of all National Ambient Air Quality Standards (NAAQS)[3]. A state's NSR program may be approved, either by incorporation into a SIP, which is approved by EPA, or by delegation to the state by EPA. If the state designs its own program, EPA may approve it so long as it meets the criteria listed in federal regulations. Otherwise, the state may request delegation of the federal NSR program, as it is written in the federal NSR regulations[4].

NSR vs. PSD: Nonattainment versus attainment areas

---

[2] EPA regulations also require States to develop minor NSR programs to address emissions growth from sources that do not trigger major source cutoffs, and from modifications that do not increase emissions above the significance levels established in regulation. This paper does not address so-called minor NSR, nor will the Report to the President.

[3] NAAQS are ambient levels of pollution established by EPA and are set at levels which protect public health and welfare with an adequate margin of safety.

[4] As noted later, the NSR requirements are different for nonattainment areas. In nonattainment areas, a state's NSR program can only be a SIP-approved program meeting the criteria listed in federal NSR regulations for SIP approval.

Generally, the term NSR is used to refer to the Clean Air Act's construction permit program for major sources. However, the major NSR program is actually comprised of two separate programs: Nonattainment NSR and Prevention of Significant Deterioration (PSD)[5]. These two programs have separate requirements to address the differing air quality planning needs in the differing areas where they apply. Nonattainment NSR applies in areas where air is unhealthy to breathe – i.e., where the established NAAQS for a Clean Air Act pollutant is not being met. These areas are called nonattainment areas. Nonattainment NSR for major sources of certain pollutants also applies in the federally designated ozone transport region (OTR), which consists of eleven northeastern states[6]. PSD applies to major sources located in areas where air quality is currently acceptable – i.e. where the NAAQS for a Clean Air Act pollutant is being met. These are called attainment areas. Because nonattainment areas have poorer air quality, nonattainment NSR requirements are generally more stringent than PSD requirements.

Determination of Major Sources and Significant Increases

The first step in determining whether new construction or modification is subject to NSR is to define the source and determine its emissions. Next, the source's potential emissions are compared to the appropriate major source threshold defined by law or regulation. Major source thresholds are defined in terms of annual emissions (i.e., tons per year). For PSD, the major source threshold is generally 250 tons per year, but the PSD major source threshold is 100 tons per year if the stationary source belongs to a list of 28 source categories (i.e. industrial groupings)[7]. For nonattainment NSR, the major source threshold ranges from 100 tons per year down to 10 tons per year depending on the severity of the air quality problem where the source is located. To be a major source under nonattainment NSR, the source must emit or have a potential to emit above the major source level the specific pollutant (or its precursor) for which the area is designated nonattainment.

A source's potential emissions, or potential to emit, is defined as a source's capacity to emit a pollutant when operating at maximum design limits except as constrained by practicably enforceable permit conditions. Practicably enforceable permit conditions limit a source's potential to emit the maximum amount possible under its physical and operational design.

A new source under construction (sometimes referred to as a greenfield source) is subject to NSR if its potential emissions will exceed the major source threshold. Applicability of NSR to greenfield sources is relatively straightforward, because the emissions from the new source are relatively easy to determine.

The other type of change that can trigger NSR is a major modification at an existing major source. The Clean Air Act defines a modification as a physical change or change in the method of operation of a major stationary source that results in an increase in emissions, or emissions of a new pollutant. Examples are a new production line,

---

[5] The term NSR usually refers to the overall program, but is sometimes also used as shorthand to refer to nonattainment NSR, which may be a source of confusion. In this document, we will use NSR to refer to the general program (both nonattainment NSR and PSD), and will use nonattainment NSR when referring specifically to NSR for nonattainment areas.

[6] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Washington, D.C.

[7] The PSD major source size for petroleum refineries is 100 tons per year. The PSD major source size for large fossil fuel fired steam electric plants is also 100 tons per year, but there are some electric generation facilities that are not fossil fuel fired steam electric plants (e.g., certain simple cycle combustion turbines). For these sources, the threshold is 250 tons per year.

an equipment upgrade, or reconfiguration of a process. Implementing regulations exempt certain activities from the definition of physical or operational change. These include, for example: routine maintenance, repair or replacement of equipment, increases in hours of operation or production rate not involving physical and operational changes (unless the increase is prohibited under an existing permit), or changes in ownership. If there is no physical change or change in method of operation, or if the change falls under one of the exemptions just described, then NSR does not apply to the change, and emissions need not be determined.

A physical change or change in method of operation (i.e., a modification) is only subject to NSR if it results in a significant net emissions increase of any regulated pollutant under the Clean Air Act. Just like the definition of a major source, the NSR regulations establish levels that define major modifications, known as significance levels, which vary by pollutant and attainment status of the area. The provision allows for *net* emissions increases if the source can offer past or future emissions decreases at its other units to counterbalance the increase from the proposed change. The net emissions increase resulting from the netting calculation must result in an increase above the significance level for PSD or nonattainment NSR to apply.

For modifications at existing sources, the net *increase* in emissions is compared against the significance level, not the entire emissions for the modified unit(s). This means that the current emissions must be known, and the future increase must be determined. Current emissions are measured using actual emissions over the recent past, usually designated as the last two years. Future increases are generally determined using potential to emit (which, as described above, is the maximum capacity to emit, except as limited by a permit)[8]. The difference between the future potential and the past actual emissions is compared to the relevant significance level. An exception is the electric utility industry, which estimates future emissions using a special calculation that resulted from a federal rulemaking following a federal court opinion[9]. The utility calculation is established in a rule, commonly known as the "WEPCO rule", which EPA finalized on July 21, 1992. This rule provides that utilities compare past actual emissions to projected future actual emissions[10].

Both EPA and regulated entities agree that similar exceptions apply in the context of NSR. The regulated entities maintain, however, that in launching an NSR enforcement initiative in 1998, EPA significantly narrowed its historical view of what constitutes "routine maintenance." The consequence, in their view, is that many practices that have long been considered not to trigger either NSPS or NSR are now being viewed as triggering NSR. As a result, they maintain, this discourages utilities and refineries from making changes in the course of the ordinary life of a utility that would significantly improve efficiency and capacity (such as the potential replacement of turbine blades with more efficient ones considered by Detroit Edison, discussed elsewhere in this material.)

The second step in determining whether NSR applies to a change is to determine whether it has resulted in a significant net emissions increase of any regulated pollutant under the Clean Air Act. The question of what the baseline should be for current emissions and what it should be for future emissions is accordingly critical and likewise the subject of controversy. For most sources, EPA's current practice is to compare a facility's

---

[8] This calculation is often referred to as the "actual-to-potential" test.

[9] See *Wisconsin Electric Power Co. vs. Reilly*, 893 F.2d 901 (7th Cir. 1990).

[10] This calculation is often referred to as the "actual-to-future-actual" test

current actual emissions to their post-change potential emissions. For the electric utility industry, its 1992 "WEPCO rule" calls for comparing current actual emissions to post-change projected actual emissions.

The Permit Application Process

Once a source determines that NSR applies, it must then prepare and file a permit application. The basic steps associated with the permit application and issuance process include: (1) preparation of the permit application and participation in any associated pre-permit application meetings; (2) issuance of permit application completeness determination by the State; (3) development and negotiation of draft permit; (4) opportunity for public notice and comment on the draft permit; (5) response of permitting authority to public comments, if any; (6) possible administrative and judicial appeals. In addition the source must address any state and local requirements associated with the project. The time and resources expended on preparing and negotiating the content of the application and addressing the NSR or PSD requirements can vary depending on the quality of the information contained in the permit application and the nature, extent and environmental impact of the proposed project. Additionally, the level of public participation can also impact the resources associated with the application process. Sometimes sources will participate in meetings with the state permitting authority and other affected parties such as EPA, local government representatives, Federal Land Managers and citizens groups prior to filing the permit application to discuss these requirements. The following discussion describes the NSR or PSD requirements that must be addressed in the permit application process.

Basic Nonattainment NSR Requirements

The Nonattainment NSR requirements apply to sources that construct or modify in an area that is designated nonattainment for one or more pollutants. These provisions apply to the pollutants for which the area is in nonattainment. If a source increases emissions of a nonattainment pollutant and increases emissions of an attainment pollutant the following provisions apply only to the nonattainment pollutant. For the attainment pollutant(s), the PSD provisions, discussed later, would apply.

New major sources and existing major sources undertaking major modifications subject to nonattainment NSR must apply state of the art emission controls that meet the lowest achievable emissions rate (LAER). LAER is based on the most stringent emission limitation in any State's SIP, or achieved in practice by the source category under review.

In order to get a nonattainment NSR permit, the applicant must also offset its emission increase by securing emission reductions from other sources in the area. The amount of the offset must be as great or greater than the new increase, and is based on the severity of the area's nonattainment classification. The more polluted the air is where the source is locating or expanding, the greater the emissions reductions required to offset the proposed increase. Offsets must be real reductions in emissions, not otherwise required by the Clean Air Act, must be enforceable by the EPA, result in a positive net air quality benefit and assure reasonable progress towards attaining the NAAQS. In general, offsets must be secured for the entire life of the source. However, under EPA's Economic Incentives Program, a source does not need to have the full amount of the offsets necessary to cover the entire life of the source at the time the source begins operation. Instead, the source can purchase additional offsets periodically to meet the offset requirement.

.

Each applicant must also conduct an analysis of "alternative sites, sizes, production processes, and environmental control techniques...[that] demonstrates the benefits of the proposed source significantly outweigh the environmental and social costs of its location, construction, or modification." The applicant must also certify that all of its other sources operating within the state are in compliance with the Clean Air Act and SIP requirements. Finally, the public must be given adequate notice and opportunity to comment on each permit application.

In addition to the basic steps identified above, when preparing a permit application, the applicant must research and propose LAER for the source category at issue and secure valid offsets as a condition of the project's approval.

Basic PSD Requirements

New major sources and existing sources that undertake major modifications that are subject to PSD must apply best available control technology (BACT). When preparing a BACT analysis, the permit applicant must typically undertake the following steps: (1) identify available pollution control options; (2) eliminate the technically infeasible options; (3) rank the remaining control technologies by control effectiveness; (4) evaluate the most effective controls (considering energy, environmental, and economic impacts) and document the results; and (5) discuss the appropriate BACT selection with the permitting authority. The permitting authority then specifies an emission limit for the source that represents BACT.

Each PSD applicant must also perform an air quality analysis, which may include pre-application monitoring data, to demonstrate that the new emission increase will not cause or contribute to a violation of any applicable NAAQS or result in a significant deterioration of the air quality. Finally, each applicant must also conduct an analysis to ensure that the increase does not result in adverse impact on air quality related values, including visibility, that affect designated Class I areas, such as wilderness areas and national parks.

Changes that do not trigger NSR

There are a number of ways that sources can undertake new construction or modification without the need for a major NSR permit. First, as noted above, there are certain activities that are exempt from NSR because they are defined in the regulations as exclusions from the definition of a physical change or change in the method of operation. For example, a routine change is exempt from NSR. Certain pollution control projects are also exempt from NSR, even those that increase emissions, if they meet environmental safeguards established by EPA.

Even if a change does not qualify for one of these exemptions, a change at a major source does not trigger NSR if the emissions increase is below the level defined as significant. Many projects have emissions increases that are below these levels and never trigger NSR. Where a project's maximum capacity to emit would be above the significance levels, a source often uses a common NSR avoidance strategy -- a limit on potential to emit, or PTE limit. In a PTE limit, a source agrees to limit the size of the proposed project's emissions increase by taking a permit limit to keep emissions below the significance level. Such limitations can be accomplished by installing modern pollution controls, or by limiting some unit's operation (e.g., limiting fuel burned or hours operated)[11].

Furthermore, even if the proposed change would result in a significant increase and cannot be limited as just described, the source may offer past or future emissions decreases at other units to offset the increase from the proposed change. Many more sources rely on netting or PTE limits to avoid NSR than actually obtain NSR permits. These transactions can result in significant emissions reductions, but a full review of these benefits is beyond the scope of this report.

General data on the NSR program's implementation

Preliminary estimates based on EPA's most recent data indicate that approximately 250 facilities apply for a PSD or nonattainment NSR permits annually. There are approximately 20,000 sources that would be classified as major under the Clean Air Act, and many more stationary sources that are not large enough to be called major. Specific permitting data for utilities and refineries are presented in the sector-specific portions of this paper; the data in this section pertain to all source categories.

Based on an EPA review of about 900 permits since 1997, the average time needed to obtain a major NSR or PSD permit, across all industries, is approximately 7 months from receipt of the complete permit application. Specific data for the electric generation and refining industries are reported in the sector-specific sections of this paper. In recent years, permitting times have been reduced for all source types.

Figure 1: Average Permitting Time for PSD permits*

Permitting Time 1997 - 1998	Permitting Time 1999 - early 2001	Overall Average Time 1997 - 2001
Average: 8 - 9 months Range: 1.5 – 35 months	Average: 6 - 7 months Range: 3 - 12 months	7.2 months

*These times are based on a total of 391 PSD sources for which sufficient data were available to calculate permitting time. Permitting time is defined to include the time period from the date on which the permit application is filed through the date on which the final permit is issued.

Improved permitting time can be explained in part by permit applicants having more pre-application meetings with the permitting agency and submitting applications with what is believed to be current BACT. Based on experience, the most common sources of delay in permit issuance are the submittal of an incomplete application, the selection of a BACT option that the permitting authority believes to be less stringent than required, and public opposition to the permitting authority's draft BACT determination. Over time, as permit engineers from the industrial sector, the permitting authority, and EPA become familiar with specific issues, permitting can be done faster, as has recently been the case with turbines. Finally, recent emphasis by EPA, state, and local permitting authorities on permitting for new electric generating capacity and refining capacity appears to be resulting in shorter permitting processes.

[11] In addition to limiting the PTE of a project to stay below the significance levels for a major modification, some sources limit their entire facility PTE to levels that keep the source from being classified as a major source.

General environmental impacts of NSR

Recent work by EPA indicates that over the period from 1997-1999, the BACT component of the PSD program has resulted in emissions reductions of over 4 million tons (or an annual average of about 1.4 million tons) compared to what emissions would have been if the controls otherwise required in the absence of PSD had been applied instead[12]. These data are based on a thorough review of approximately 900 PSD permits issued since 1997. Figure 2 summarizes these data by pollutant.

Figure 2: Estimated Emissions Avoided Due to PSD BACT Permitting (1997 – 1999) (short tons)

PM/PM10	180,000
SO2	1,260,000
NOx	2,540,000
CO	65,000
VOC	25,000
TOTAL	**4,100,000**
Annual average over time period	***1.4 million tons per year***

The review on which these numbers are based included only PSD permits. Therefore, these emissions reductions estimates do not include emissions reductions for control technology and offsets in nonattainment areas.

The emissions reductions that result from pollution control required under NSR are not the only way that the NSR program keeps pollution out of the air. Each year many companies make modifications to existing facilities, and even construct entirely new facilities, without obtaining and NSR permit by keeping emissions lower than the amounts for which permits are required. This process is sometimes referred to as "netting out" of NSR. [13] Because EPA is usually not involved when companies make changes that do not require NSR permits, we do not have data on the amount of pollution avoided as a result.

Benefits Associated with Electricity Generating Emissions Reductions Realized Under the NSR Program

[12] Typically, in the absence of BACT, the controls required would be a federal New Source Performance Standard (NSPS), and/or a limit from an applicable State Implementation Plan (SIP).

[13] For example, if a power plant located in an attainment area makes a change that would increase its emissions of NOx by 50 tons per year but at the same time installs pollution control technology that would reduce its NOx emissions by 35 tons per year, the plant would not have to obtain an NSR permit because its net emissions increase (15 tons per year) would be less than the 40 tons per year that makes a change a major modification.

Based on the estimated emissions avoided due to PSD BACT permitting as reported in the table above, EPA estimated the magnitude of the benefits associated with this program. This estimate is lower than the actual benefits of the NSR program because not all the health and environmental benefits are captured, nor are all the benefits of nonattainment NSR captured. Also, the estimate does not capture the benefits of the reductions in emissions of pollutants other than SO2 or NOx.

Based on the figure above, roughly 400,000 tons of SO2 and 822,000 tons of NOx emissions are avoided annually as a result of the PSD program. Ninety percent of these reductions are thought to be from electricity generating facilities. Based on previous EPA analyses (Hubbell 2001), the average health-related benefits per ton of NOx reduced are around $1,300, and the average benefits per ton of SO2 reduced are around $7,300 for electricity generating units of this type and proximity to population. For simplicity, estimates are provided only for health impacts that generally account for over 90 percent of monetary benefits in previous analyses.

II. Electric Power Industry

1. Historical NSR Permitting Data

This section presents a summary of the available data for NSR permitting for the electric generation industry. Most of the available information comes from the EPA regional offices. Because states issue the vast majority of nonattainment NSR and PSD permits, they are the best source for historical permitting data. EPA Regional offices work with the states to track various program data. However, states are generally not required to submit permitting data to EPA. Recent tracking has focused on PSD permitting for combustion turbines. Limited PSD data are also available for coal-fired power plants and for the broader electric generating sector. The summaries in this section do not include nonattainment NSR or minor source permits because of the limited availability of data.

Since 1995, 274 PSD permits have been issued nationally for new and modified electric generation facilities. Most of these have been for gas turbines, but some PSD permits have been issued for other electric generators as well. The combined new generating capacity for these PSD-permitted facilities is approximately 150,000 MW.

For coal-fired electric generation, there have been at least 10 PSD permits issued nationally, reflecting a combined generating capacity of approximately 5,600 MW. The average permitting time for these units was approximately 10 months[14]. For gas turbines, there have been over 250 PSD permits issued nationally, reflecting a combined generating capacity of about 138,000 MW. The average permitting time for these units was approximately 7 ½ months. However, more recent data indicate that, for turbines, the average time is decreasing, most likely because the process for determining BACT is accelerating as applicants and permit writers become more familiar with emerging NO_x control technology.

Electric Power Industry Enforcement Actions

[14] One anomalous case is an appealed PSD permit that became a subject of Federal litigation, which significantly lengthened its issuance time. If this case is removed, the average permitting time is 8 months.

EPA and several states have taken enforcement actions against owners and operators of several coal-fired plants, alleging that a number of facilities had been modified without NSR permits. In connection with all of the notices of violation filed on the coal-fired plants for the types of modifications noted above, EPA is unaware of any minor NSR permits issued for the activities in question. These modifications tended to fall within four general categories:

(1) Construction without a permit: EPA has identified instances where sources completed construction of entire coal-fired steam generating units without incorporating modern pollution controls. In these cases, the source argues that construction permits issued in 1974 exempt those sources from the 1977 regulations, notwithstanding the 18-month limitation in the regulations governing the life of construction permits.

(2) Expansion of capacity: EPA has identified a number of instances where the hourly capacity of the unit was increased. An example of such a modification is a company that increased the amount of coal being fed into the boiler by 5 tons per hour.

(3) Redesign of existing units: Between the 1950s and 1970s, the size of power plant units increased from 50 MW to over 1000 MW units. Not all of these large units were immediately successful. EPA identified a number of instances where, in the first few years after installation, relatively new installations were redesigned and modified to eliminate or mitigate original design defects, and such modifications led to significant increases in emissions.

(4) Life Extension Projects: EPA has identified a number of projects undertaken by power plants that extend the useful life of the boilers beyond that contemplated when the facilities were built. For example, some power plants replaced major components (e.g., economizers, super heaters) after 30 years of use and in a manner that resulted in an emission increase from the unit. EPA's position is that these types of physical changes trigger NSR/PSD under existing law and regulations.

Following on these investigations. EPA engaged the operators of the investigated facilities in discussions aimed at resolving the alleged violations. EPA has reached a final settlement with one operator, Tampa Electric, and has reached agreements in principle with Cinergy, Inc. and Virginia Power. Those settlements provide for a total emissions reduction of approximately 305,000 tons per year of NOx and 641,000 tons per year of SO2 over a period of time that extends to December 31, 2012.

EPA currently is engaged in settlement discussions with a number of other utilities. These discussions are aimed at reaching agreements that provide flexibility in the operation and modification of utility systems and substantial reductions in emissions.

2. Factors Affecting Investment in New Capacity

This section examines those factors that are considered by power sector decision-makers when building and siting a new plant, and when deciding to expand an existing plant. It is based on a review and analysis of available literature performed for EPA by ICF Consulting. Although the review found limited data, some information was available that shed light on considerations important to developers.

A decision to invest in a new power plant or expand an existing one requires simultaneous evaluation of strategic and siting considerations and permitting issues. Company officials and developers do not typically enumerate the relative importance of different factors in evaluating projects. Rather they seek to identify the impact of all the different elements on the rate of return (ROR) of each potential investment option. An investment's ROR is the most common metric by which investors organize, standardize and evaluate all pertinent information in order to make an informed investment decision. Although decision makers often rely on ROR projections to make investment decisions, whether for new plant construction or expansion of existing facilities, they remain sensitive to intangibles such as public opinion.

In general, there are three primary considerations in project development:

1. Strategic Considerations: whether a market for power generation is likely to be the most profitable among those a firm wants to locate in;

2. Siting Considerations: access to the power transmission grid, reliability of natural gas and coal delivery systems, water availability, as well as local environmental and zoning issues.

3. Permitting Issues: time and cost of obtaining various permits, including air and operating permits.

Strategic considerations. Factors like capital outlay, power prices, and fuel costs generally have the most impact on ROR. In addition, uncertainty about power prices and fuel costs introduce risk into the investment decision. The other notable component of the strategic considerations of interest in this report is environmental costs, primarily pollution control equipment. These usually have a small to moderate impact on ROR. If the spread between fuel and power prices is sufficiently high, environmental cost may not affect a decision about whether or not to construct. However, in some instances where the facility minimally meets the required ROR, pollution control requirements can change the investment decision of a plant. Environmental cost, as with any other cost component, only matters to the extent that it impacts the ROR. Generally, environmental costs are one of many cost components under consideration, and not necessarily the deciding factor.

Siting considerations. These factors have important implications for decisions to invest in a new plant in one location versus another, or to expand at an existing facility. Recently, the difficulty in finding acceptable sites has more important in the decision calculation.

The importance of siting is perhaps most obvious in the decision to invest in a new facility or to expand an existing facility. An existing site provides numerous beneficial advantages – an existing access to transmission lines, a ready supply of fuel sources, appropriate zoning laws, and water sources. Furthermore, expansion of existing facilities may not always require significant additional permitting time if the definition of the source does not change. However, expansion of an existing facility may be limited by its physical capabilities, and new construction then may be necessary.

Permitting issues. These issues have become an integral part of the project development process. Permitting can be a costly process that negatively impacts ROR. Most developers describe permitting as an extremely complex and time-consuming process. The financial impacts from permitting (including NSR) can change the economic feasibility of the project. Permitting (including required public hearings and comment processes) can be costly not only because of the time and human resources involved, but also because of uncertainty and delay. Delay, for example, can cause a developer to miss advantageous financial circumstances when interest and equity costs are low.

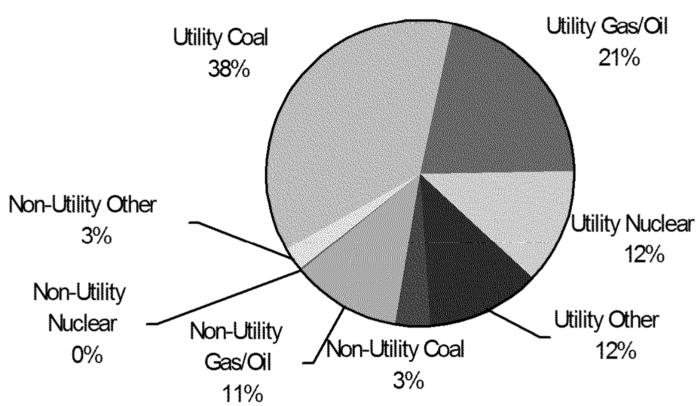
This cost of financing can have a large and negative impact on ROR.

3. Trends in Electric Capacity and Utilization

This section summarizes the trends in electric capacity utilization over the last 20 years, particularly the last decade. Any examination of the trends in electric capacity and utilization over the last 20 years must be placed within the context of deregulation in the electric generation industry. Three seminal laws – the Public Utility Regulatory Policies Act (PURPA) in 1978, the Energy Policy Act (EPACT) in 1992, and Federal Energy Regulatory Commission (FERC) Order 888 in 1996 – set into motion various measures to increase competition in the electric generation industry and to enhance transmission access for sources other than utilities. Deregulation in electric generation not only has reshaped the market for electricity, but has fundamentally altered the strategies that generating companies use in managing their portfolio of assets.

In 1999, total U.S. electric generating capacity was 781 GW, of which utilities accounted for approximately 83 percent. In 1992, non-utilities accounted for less than 7 percent of total electric capacity, compared to 17 percent in 1999. The emergence of non-utilities as a more significant component of the electric generation industry is the direct result of deregulation activities that created a more vibrant generation market and improved access to transmission lines. Figure 3 below highlights utility and non-utility electric capacity in 1999.

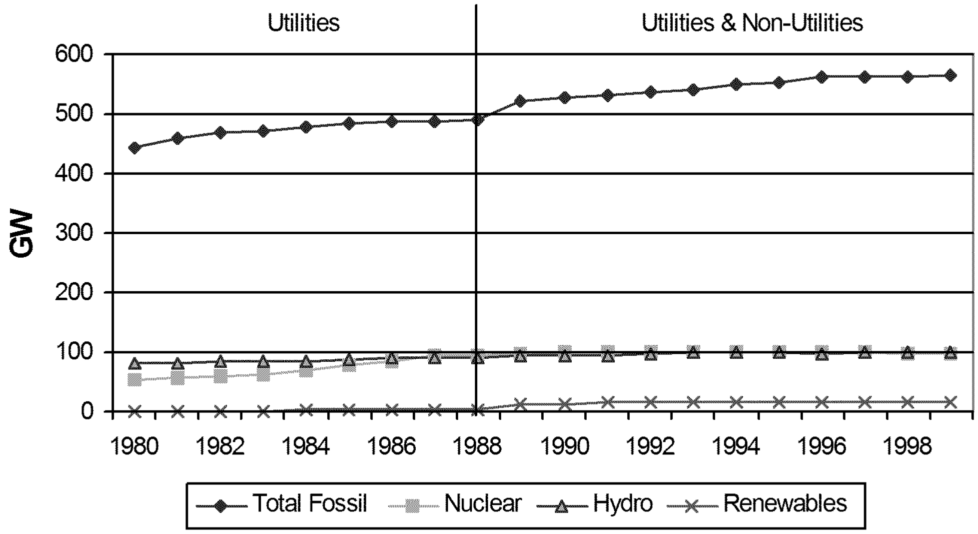
Figure 3: Utility and Non-Utility Capacity in 1999



Source: Annual Energy Review, EIA

Non- utilities have increased their share of total electric capacity through new capacity additions and by acquiring divested utility assets. In 1997, for instance, 53 GW of utility assets were for sale; in 1998 an additional 77 GW of utility assets were made available for auction. By April 2000, 156 GW of utility capacity, or 22 percent of total capacity, had been sold, transferred to unregulated subsidiaries, or were for sale. Many of these assets were acquired by non-utilities seeking to penetrate generation markets. Similarly, between 1998 and 1999 non-utilities installed approximately 12 GW of capacity, outstripping the net capacity additions by utilities. Figure 4 shows the trend in total U.S. capacity between 1980 and 1999.

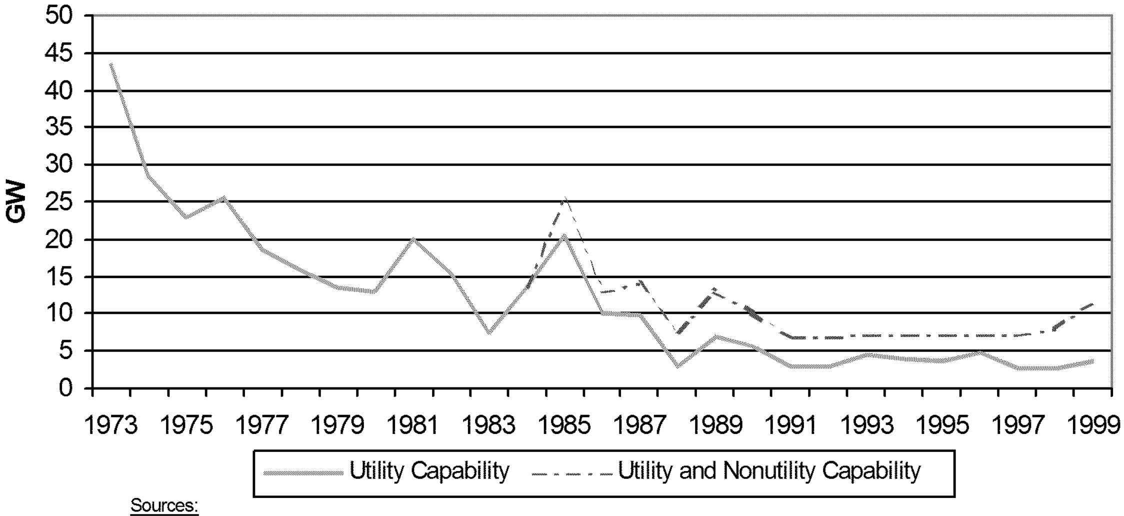
Figure 4: Total U.S. Electric Capacity (1980-1999)



Source : Annual Energy Review, EIA, Table 8.5

Between 1989 and 1999 electric capacity grew by 8 percent from 725 GW to 781 GW. This is in sharp contrast to the pace of new capacity between 1980-1988, when the generating capacity of electric utilities alone grew by 17 percent from 579 GW to 677 GW. (Data on non-utilities are not available for the years prior to 1989.) Figure 5 highlights the trend in net capacity additions. The capacity data in Figure 5 reflect summer dependable capacity, which is a measure of a unit's capacity during the summer months.

Figure 5: Annual Net Capacity Additions (Net Summer Dependable Capacity) (1973-1999)



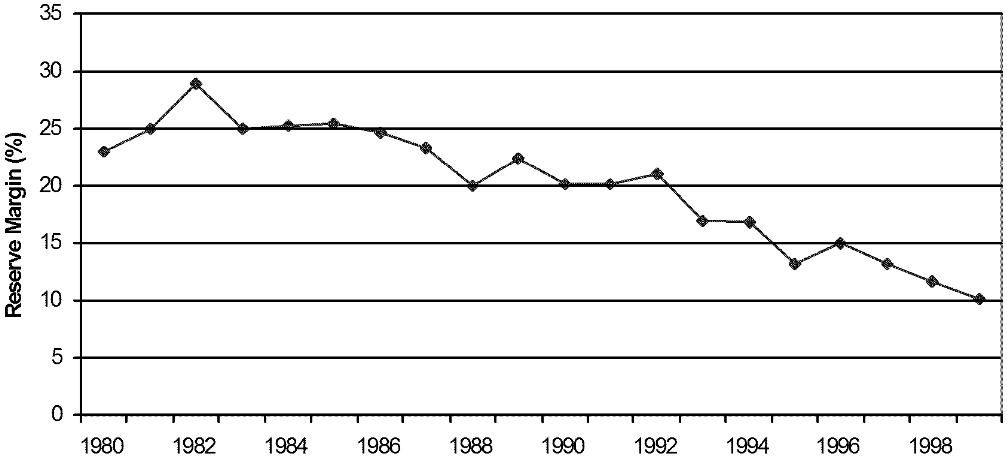
Sources:
Data from 1973 through 1993: EIA, *Annual Energy Review*
Data for utilities from 1994 onwards: EIA, *Inventory of Power Plants*
Data for non-utilities from 1994 through 1997: EIA, *Electric Power Annual Vol. II*
Data for non-utilities from 1998 and 1999: EIA, *Inventory of Non-utility Power Plants*

While the growth in capacity during the 1980s was driven largely by reliability concerns and consistent overestimates of future peak demand, the decline in the rate of capacity growth during the 1990s has been attributed largely to deregulation and the emergence of non-utilities. During the 1970s and through 1983, peak demand forecasts were consistently high. Since utilities based their capacity planning on expected future peak demand, there was significant investments in additional capacity, mostly coal-fired and nuclear facilities. Additionally, the northeastern blackouts of 1965 and the formation of the North American Reliability Council (NERC) put added emphasis on the reliability of electric bulk power systems. The economic and regulatory climate during the 1980s also helped spur investments in new generation capacity. Since utilities were regulated, they were guaranteed some level of return on their investment. Fuel prices also dropped sharply during that time. Average coal prices, after peaking in 1978 at $45 per short ton (real 1996 dollars), had dropped to $25 (real 1996 dollars) by the end of the 1980s.

The construction boom in capacity during the 1980s subsided during the 1990s as EPACT and FERC Order 888 initiated deregulation. Utilities were reluctant to make major investments in new plant capacity because of uncertainty about how the costs would be recovered and the risk of capital investments being stranded under deregulation. Declines in utility capacity additions, however, were offset by non-utility investments in new capacity. While EPACT made it easier for exempt wholesale generators to come online, FERC Order 888 ensured that non-utilities would be able to compete fairly against utilities through equal access to transmission lines. Thus, by the late 1990s pure non-utility plants were being built and operated.

The advent of deregulation and the emergence of non-utilities in electric generation has had significant impacts on reliability planning and investments in new capacity during the 1990s. Reserve margins, the percent of capacity over peak demand, is the most frequently used metric for reliability. Figure 6 highlights the trend in total U.S. reserve margins over the period 1980-1997.

Figure 6: Reserve Margins (Percent Capacity Over Peak Demand) (1980- 1997)



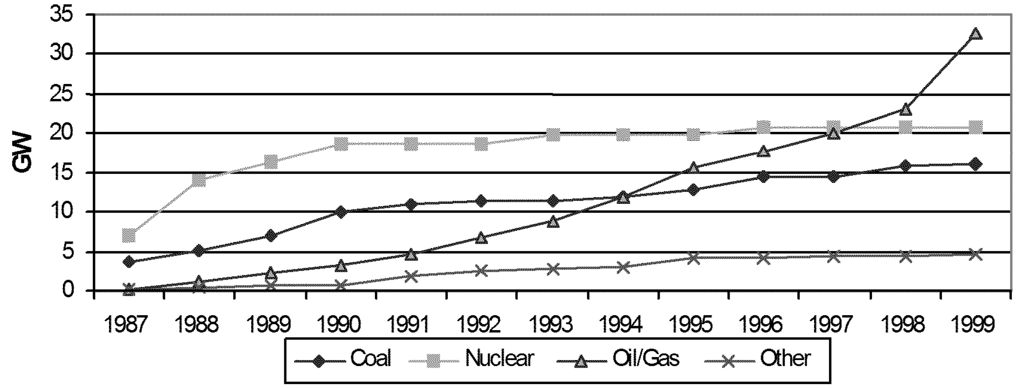
Source: EEI, *Statistical Yearbook of Electric Utility Industry*
Note: Reserve Margin is calculated as: (Capability - Peak Load)/Capability * 100

After peaking in the early 1980s at 33 percent, reserve margins declined rapidly and are currently at 12 percent. This drop in reserve margins coincides with the emergence of non-utilities and deregulation. Forecasted peak demand also was consistently lower than actual peak demand during the years after 1983. [15] Collectively, the risk of stranded investment, deregulation, and the emergence of non-utilities reduced the construction boom in new electric capacity during the 1990s.

During the 1990s coal-fired and nuclear plant construction declined, while the construction of natural gas-fired units increased. Some utility and power plant owner have contended that existing and potential future environmental regulations limit the economic possibilities for new coal-fired plants. Additionally, public opposition to the construction of new coal-fired and nuclear plants has increased. Another reason for the shift in construction from coal and nuclear to gas may be the fact that deregulation favors construction of less capital-intensive projects. The decline in coal and nuclear construction, however, was offset by non-utility investment in natural gas-fired combined cycle and combustion turbines. Figure 7 highlights cumulative capacity additions by energy source for 1987 - 1999. Figure 8 highlights the additions and retirements of coal-fired capacity between 1989 and 1997.

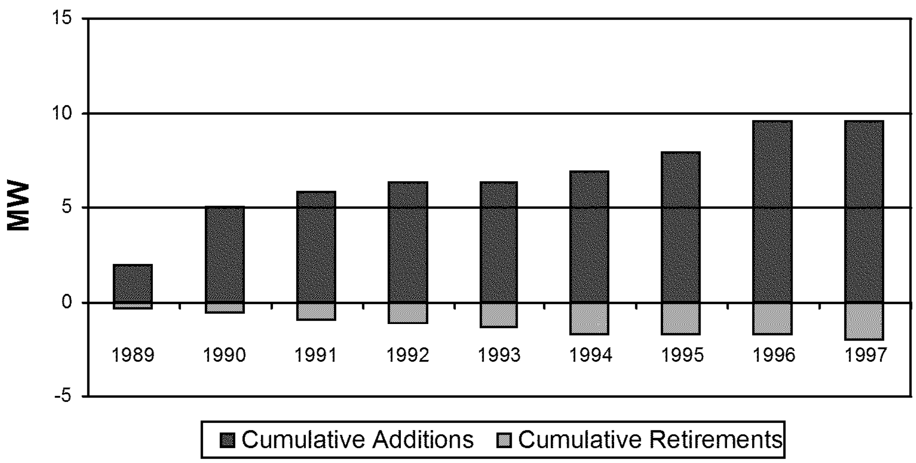
[15] EIA, Performance Issues for Changing Power Industry, January 1995 (Appendix, p.31)

Figure 7: Cumulative Capacity Additions by Energy Source (1987-1999)



Sources: EIA, *Inventory of Power Plants*, 1990, 1992, 1993, 1996, 1997, 1998, 1999,
EIA, *Inventory of Non-Utility Power Plants*, 1998, 1999.
Note: Capacity additions in 1998 and 1999 include non-utilities; prior to that only utility information was available.

Figure 8: Cumulative Additions and Retirements of Coal-Fired Capacity (1989- 1997)

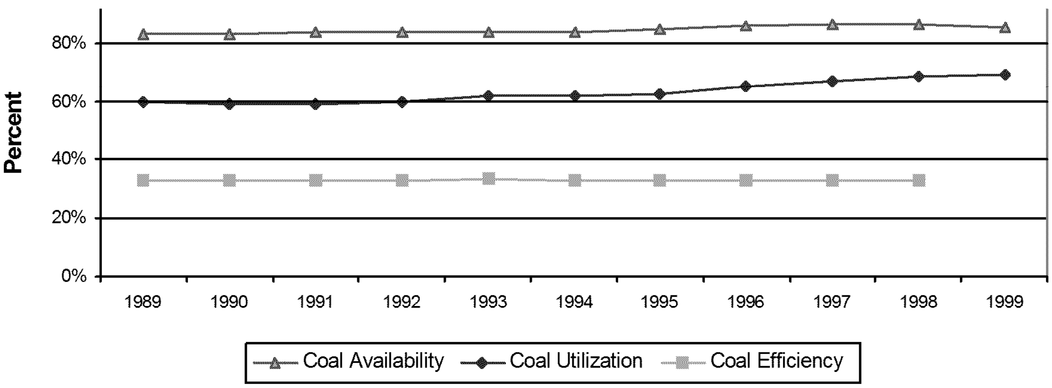


Technological innovations in the performance of gas turbines also contributed to growth in new gas-fired capacity. Throughout the 1990s the efficiency of gas turbines improved significantly, providing generators with an effective strategy for penetrating markets. Rather than compete against base load units, non-utilities wanted to compete against the less efficient, older oil/gas steam units that provided electricity during peak loads. Non-utilities with their efficient gas units could penetrate those markets successfully.

The increased utilization of coal-fired capacity during the 1990s stemmed from the decline in capacity addition and reserve margins over that same period in time. Since fewer new units were being added, increased utilization of the existing units was necessary to satisfy increasing electricity demand. Deregulation and a decline in fuel prices were also important factors in increased utilization. Between 1989 and 1999 average real coal prices dropped by 34 percent from $26 per short ton (real 1996 dollars) to $17 per short ton (real 1996 dollars)[16]. Natural gas prices declined similarly, as did operation and maintenance costs. Between 1989 and 1997, total non-fuel expenditures for coal steam units decreased by 13 percent while generation increased by 14 percent. As a result, average operation and maintenance cost for coal generation declined from $5.22 mill/kWh (1997 dollars) in 1989 to $3.96 mill/kWh (1997 dollars) in 1997[17].

In addition to putting downward pressure on operation and maintenance costs, deregulation also pressured existing plant owners to reduce both scheduled outages (planned plant shutdowns for maintenance and repair) and forced outages (unplanned plant shutdowns). Between 1989 and 1999, both scheduled and forced outage rates for coal-fired plants declined, scheduled outages by 13 percent and forced outages by 19 percent. Figure 9 highlights the trends in availability for coal-fired capacity. The average efficiency of coal-fired capacity, however, remained relatively unchanged.

Figure 9: Availability, Utilization, and Efficiency for Coal-Fired Plants (1989-1999)

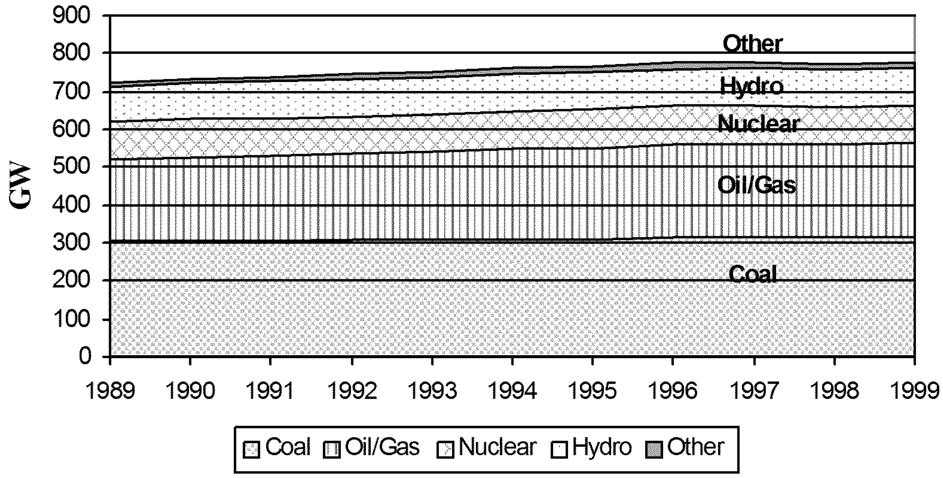


Source: Coal efficiency: Parker, Larry B. and Blodgett, John E., "Air Quality and Electricity: Enforcing New Source Review,", January 31, 2000.
Coal availability: 1999 Generating Availability Report (GADS), NERC
Coal utilization: EIA, *Annual Energy Review,* Tables 8.2 and 8.5

The capacity mix of existing units over the last decade has remained fairly stable. Figure 10 highlights electric generation by different types of fuel for the period 1989-1999. Coal-fired capacity has remained at around 40 percent, oil/gas at around 30 percent, and nuclear and hydro power at about 13 percent each. The remaining capacity consists of renewable fuels and others. Significant nuclear capacity was added during the 1980s. The mix of capacity additions, however, is significantly different from the mix of existing capacity during the 1980s. (Note for Figure VIII: Data on non-utility additions by energy source were available only for 1998 and 1999.)

[16] EIA, Annual Energy Review 1999, Table 7.8.
[17] Beamon, Alan J. and Leckey, Thomas J., "Trends in Power Plant Operating Costs," EIA, 1999.

Figure 10: Total Capacity (GW) – Utilities and Non-Utilities (1989-1999)



Source: EIA, *Annual Energy Review*, Table 8.5

In the future non-utilities are likely to command more of the capacity and generation share. The Energy Information Administration (EIA) projects that generation from coal and natural gas will continue to increase to offset the projected retirement of nuclear capacity. EIA also forecasts that since deregulation favors less capital-intensive plants, new gas capacity will continue to be added. However, the recent surge in natural gas prices has reinvigorated the interest in coal plants. While the trends over the last 10 years are likely to continue, particularly for new natural gas capacity, competitive markets made facility owners extremely sensitive to cost pressures. Significant changes in the relative cost of coal and gas, for example, could lead to investments in significant new coal-fired capacity. Additionally, the recent California experience and concerns about similar shortages in the northeast again has made reliability an important concern.

4. Data on Costs of Pollution Controls[18]

In general, capital expenditures for air pollution control as a percentage of total capital expenditures on new plant construction are significantly lower than those expenditures on existing plants. Pollution control equipment retrofitted to existing units are subject to physical and engineering constraints (including the availability of needed space, removal of existing equipment, additional engineering required to fit new equipment into the existing site, etc.) that add to the cost. In a new plant, on the other hand, optimal configurations of generating units and all necessary pollution control equipment can be built in at the design phase.

[18] The control technology cost estimates were obtained from various sources. Therefore the cost estimates may not be consistent in terms of their assumptions or estimation methodology. The range of pollution control costs, therefore, should only be considered illustrative and not as upper or lower bound of actual pollution control costs that will be incurred by generating units. For a more complete information concerning the cost estimates please refer to Exhibit 1 in the Draft Report of the "Review of Data on the Impact of New Source Review on Investment Decisions- Power Generation and Refinery Sectors" prepared for EPA by ICF Incorporated.

The ratio of pollution control capital expenditures to the total capital expenditures differs according to the size of the units. In general, over a certain range of generating capacities, larger units tend to have lower costs on a unit-cost basis ($/kW) due to economies of scale. In addition, total pollution control costs differ depending on the location of the generating units, whether they are new or modified. Furthermore, these costs depend on whether the generating unit is to be located in an attainment or non-attainment area.

Attainment Areas: In attainment areas, pollution control costs are limited solely to the costs of control equipment. These costs, however, depend on the location of the plant, plant characteristics, and the amount of plant emissions. These factors determine the stringency of required BACT controls.

Non-Attainment Areas: In nonattainment areas, pollution control costs consist of control equipment costs plus the costs of offsetting new emissions of pollutants for which the area is in non-attainment. In this paper the costs of offsets have not been included in the pollution control expenditures, since the costs of offsets vary widely by specific location and the pollutant being controlled. An analysis by ICF Consulting [19] (hereafter called the "ICF report") provides illustrative cost shares of pollution control expenditures. Exhibit 1 in the ICF report indicates that the pollution control expenditures are highest for new coal-fired units and lowest for new combined cycle units. [20] Further, the pollution controls cost shares are higher in nonattainment areas than in attainment areas. Other conclusions that can be drawn from Exhibit 1 include:

Attainment Areas

- For new coal-fired units, pollution control capital expenditures account for about 20 to 27 percent of total construction capital costs.
- For new coal-fired units, annual pollution control expenditures account for about 23 to 31 percent of total annual generating unit costs.
- For new combined cycle units, however, pollution control capital expenditures account for only about 2 to 5 percent of total unit construction capital costs.
- For new combined cycle units, annual pollution control expenditures account for about 5 to 14 percent of total annual generating unit costs.
- For repowered combined cycle units, pollution control capital expenditures account for only about 5 to 6 percent of total construction capital costs.

---

[19] ICF, Inc. "Review of Data on the Impact of New Source Review on Investment Decisions." Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. June 22, 2001.

[20] The control technology cost estimates were obtained from various sources. Therefore the cost estimates may not be consistent in terms of their assumptions or estimation methodology. The range of pollution control costs, therefore, should only be considered illustrative and not as upper or lower bound of actual pollution control costs that will be incurred by generating units. For a more complete information concerning the cost estimates please refer to Exhibit 1 in the Draft Report of the "Review of Data on the Impact of New Source Review on Investment Decisions- Power Generation and Refinery Sectors" prepared for EPA by ICF Incorporated.

∀ For repowered combined cycle units, annual pollution control expenditures account for about 5 to 15 percent of total annual generating unit costs.

Nonattainment Areas

∀ For new coal-fired units, pollution control capital expenditures account for about 24 to 27 percent of total construction capital costs.

∀ For new coal-fired units, annual pollution control expenditures account for about 27 to 31 percent of total annual costs.

∀ For new combined cycle units, however, pollution control capital expenditures account for only about one to 14 percent of total construction capital costs.

∀ For new combined cycle units, the annual pollution control expenditures account for about 5 to 17 percent of the total annual generating unit costs.

∀ For repowered combined cycle units, pollution control capital expenditures account for only about 2 to 15 percent of the total construction capital costs.

∀ For repowered combined cycle units, annual pollution control expenditures account for about 5 to 29 percent of total annual costs.

Costs of Offsets:

As noted earlier, in nonattainment areas newly constructed or modified plants are required to purchase offsets at a one-to-one or greater ratio (depending on the SIP requirements) to offset projected emissions increases of those pollutants for which the area is in non-attainment. Figure 11 (taken from the ICF report) illustrates the average costs of ERCs for specific pollutants.

Figure 11: ERC Bid and Offer Prices for Specific Criteria Pollutants (May 2001)

(current $ per ton per year)

Location	**SO_2**	**NO_x**	**PM_{10}**	**VOC**	**CO**
Highest Offset Price (Nation-wide)	$ 7,667	$ 104,000	$ 75,693	$ 52,500	$ 35,381
Average Offset Price (Nation-wide)	$ 6,834	$ 14,644	$ 27,243	$ 6,253	$ 15,710
Lowest Offset Price (Nation-wide)	$ 6,000	$ 475	$ 4,500	$ 300	$ 3,750
Highest Offset Price (Excl. California)	$ -	$ 12,000	$ 4,500	$ 10,000	$ 8,000
Average Offset Price (Excl. California)	$ -	$ 5,531	$ 4,500	$ 3,642	$ 8,000
Lowest Offset Price (Excl. California)	$ -	$ 475	$ 4,500	$ 300	$ 8,000

5. NSR Impacts on Capacity Additions

The purpose of this section is to summarize data from relevant studies or articles on topics related to NSR and investment in new generating capacity. This section is based on a literature search about the impact of NSR on new power plants. Though numerous articles discussed legal aspects of NSR, only a small number directly discussed the impacts of NSR on the location of new utility plants.

In summarizing the literature on the impacts of NSR on new construction, the primary question was whether or not NSR had affected the economic behavior of new plant owners or developers. In other words, did NSR change the course of new plant construction, or would the same new plants have been built with or without NSR? No studies nor could be found that answer this question. Consequently, three sub-questions were developed, and, taken sequentially, they provide indicators for the primary question. The sub-questions include:

Do the requirements of NSR affect the cost of new plants?

In order for NSR to have an impact on the location of new plants, it must affect the cost or revenues of new plants.

Has NSR changed the economics of new plants?

If NSR influenced either the cost or revenues of new plants, was it sufficient to change the economics or financial outlook for new plants?

Have utilities and developers responded to the changes in economics of new plants resulting from NSR?

If NSR changed the economics or financial outlook for new plants, did power plant owners and developers fully internalize the changes and then adjust their decision process?

<u>Do the requirements of NSR affect the cost of new plants?</u>

Based on the literature survey, NSR has affected the cost of new plants in a formal and informal way. Formal impacts include the quantifiable costs of pollution control and the direct costs associated with permitting. Informal impacts include intangible elements such as real or perceived regulatory barriers, public opinion about the new plant, and permitting delay cost.

The cost of building a new plant is dependent, among other things, on pollution control equipment mandated by NSR requirements. Major new sources in attainment areas, for instance, are required to install Best Achievable Control Technology (BACT) and satisfy Prevention of Significant Deterioration (PSD) requirements. Although state agencies can determine BACT taking into account energy, environmental, and economic impacts, BACT cannot be less stringent than NSPS requirements. In non-attainment areas, major new sources need to install Lowest Achievable Emissions Rate (LAER) technology and provide offsets for the emissions from the new source[21]. Whether in attainment or non-attainment areas, new coal-fired plants at a minimum must include pollution control

[21] Parker, Larry and Blodgett, John, "Electricity Restructuring: The implications for Air Quality," Congressional Research Service Report for Congress, Updated January 2001.

equipment for SO_2 and NO_x. Estimates of pollution control costs have been varied. The Congressional Research Services (CRS) estimated that pollution controls for SO_2 cost 0.53 cents/kWh (1995 dollars), while controls for NO_x cost 0.17 cents/kWh.[22] A study by E^3 Ventures, Inc. estimated environmental costs for new coal-fired plants to be about 0.5 cents/kWh.[23]

Some reports have discussed the costs associated with NSR permitting. One author concluded that it would be "prudent to involve environmental managers, operations personnel, management, consultants, and legal counsel in process".[24] Although the article does not provide any indication of what the costs might be, it can be inferred that time spent by some or all of the suggested personnel would imply some cost, albeit a small fraction of the total project cost.

Many reports have discussed the informal impacts of NSR on the costs of new plants, although these costs are generally difficult to quantify. Perhaps the most visible of these impacts is the involvement of the public in the permitting process. NSR is an example of a program that explicitly calls for public involvement, including a right to contest permitting decisions. In an article discussing public participation in the review process, one author wrote that "opposition is widespread…a significant movement of grass root activists".[25] This article provides summaries of case studies on how public involvement terminated or changed the proposed project.

Alliant was so sensitive to public opinion that, even before considering a new coal-fired plant in Iowa, the company surveyed its customers to assess their receptiveness to a coal-fired plant, indicating that a survey was necessary because "the industry in general has been battle scarred."[26] The Alliance of Energy Suppliers[27] suggested that public relations and education be explicitly included in the project development budget for a new plant. In New York, Heritage Power LLC negotiated siting and operation permits for an 800 MW natural gas-fired combined cycle facility with approval conditions that included the source providing public benefits to the county.[28]

A few reports also discuss legislative barriers to new plants, although it is unclear whether these barriers were real or perceived. In announcing a new gas-fired plant in Mississippi, a spokesperson for Duke Energy concluded that the Clean Air Act restricted the construction of new coal-fired plants.[29] On the other hand, a recent

[22] Ibid., Table 5.

[23] E^3 Ventures, Inc., "Plain Language Guide to Power Investments", March 2001.

[24] Belden, Roy S., "Navigating the Permit Process," Independent Energy, May/June 1995, pages 56-59.

[25] Deisinger, Chris, "The Backlash Against Merchant Plants and the Need for a New Regulatory Model," Electricity Journal, December 2000.

[26] "Alliant Gets Ahead of the Curve in Coal Plant Strategy," Coal Week, April 23, 2001.

[27] Picardi, Al, Hodges, Mark and Tarr, Nancy, "Fast-Track Development Strategies," Electric Perspectives', March/April 2001. Posted on Alliance of Energy Suppliers website, URL:// www.eei.org/alliance.

[28] Fitting, Beth, "State Oks Building New Power Plant," Business Journal, February 9, 2001, page 1.

[29] Gillette, Becky, "Power Plant Construction in Mississippi Has Major Economic Impact," Mississippi Business Journal.

news report indicated that 34 new coal-fired plants totaling 20,000 MW had been proposed.[30] It is difficult to determine if NSR is a perceived or real regulatory barrier to the construction of a new coal-fired plant, since the recent announcements of proposed plants may have been motivated by high gas prices and electricity shortages.

Some of the available literature asserts that the NSR process is long and can be cumbersome. For example, after evaluating NSR and NSPS, the National Coal Council concluded that "permitting is a lengthy process" that can last years.[31] Some literature suggests that the lengthy permitting process might have an important informal impact on the cost of new power plants, since it often leads to some loss in flexibility. The Alliance of Energy Suppliers warns its members that "unexpected delays or unforeseen permitting difficulties are almost always costly and, at the extreme, can kill a project." This article adds that lengthening the permitting time from a few months to a year not only increases the cost of the project several times but also implies lost sales revenues.[32]

Has NSR changed the economics of new plants?

To answer this question, the literature was searched for data indicating change in the relative costs of different types of new plants due to NSR. If, for example, coal was the preferable fuel before NSR, is there any evidence that NSR changed that preference? In summary, the available literature is inconclusive. The search suggested that more data are needed to quantify the impacts of NSR on the economics of new plants.

In 1998, Resources Data International (RDI) released a study naming the top ten utility winners and losers due to the impacts of the Clean Air Act. RDI reported that the winners would incur no new costs and losers would incur high costs in meeting new regulations.[33] Although the study targeted existing utilities, it concluded that clean air requirements could penetrate through to the bottom line – revenues and asset values.

A more recent article evaluates the potential for new plants in California. Based on rates of return on investment, the author concluded that there are sufficient returns to attract new power plants to California despite the many inherent risks. The author wrote that "environmental constraints and/or opposition to power plant siting are the only serious impediments to new power plant construction in California".[34] In a similar vein, the National Coal Council reported that the cost of new pulverized coal-fired plants fully equipped with NSR required control technology is lower than the cost of existing coal-fired plants, and NSR plants can be more utilized much more fully than existing coal-fired plants.[35]

---

[30] Reuters News Agency, June 5, 2001.

[31] "Increasing Electric Availability From Coal-Fired Generation in the Near-Term," The National Coal Council, May 2001, Page 27.

[32] Picardi, Al, Hodges, Mark and Tarr, Nancy, "Fast-Track Development Strategies," Electric Perspectives', March/April 2001. Posted on Alliance of Energy Suppliers web-site: URL://www.eie.org/alliance.

[33] Lobsensz, George, "A New Top 10 List Names Utility Winners, Losers from Clean Air Impacts," Energy Daily, October 27, 1998.

[34] Schmidt, Michael, "California's Power Gamble: Long Term Contracts," Public Utilities Fortnightly, page 40.

[35] The National Coal Council, "Increasing Electricity Availability From Coal-Fired Generation in the Near-Term," May 2001.

Some of the surveyed literature attributed the decline in new construction to non-NSR impacts. In a recent news release, Reuters reported that 34 new coal-fired plants totaling over 20,000 MW have been announced.[36] This observation from Reuters is interesting because it marks a sharp departure from the past decade, when very few new coal-fired plants have been built. At the same time, it must be noted that this observation was made in the context of historically high prices for natural gas. A report by the CRS suggested that the smaller number of new coal-fired plant construction over the past decade may be due to the fact that natural gas-fired plants were the technology of choice in deregulated electricity markets. The CRS report contended that the decline in new coal-fired capacity, operated as base load capacity, also may have been due to the current surplus in base load capacity. Furthermore, the report contended that current average capacity margins of 15 percent (ranging from 13 to 18 percent) could increase to 15.6 percent by 2008 if announced new non-utility plants come online as anticipated.[37]

In evaluating whether NSR has had an impact on the location of new power plants, it is important to consider whether the formal or informal impacts of NSR have realigned the cost economics of new power plants. One article reviewing the broader impacts of environmental regulation argued that emissions control projects were as much a response to competitive pressures as to environmental regulations. Quoting a project manager at Connectiv, the article stated that long-term commitments with environmental equipment suppliers were important to overall project execution.[38] Similarly, the New York State attorney general said low demand and not environmental regulations had led to few plants being built. He urged the Senate Environment and Public Works Clean Air subcommittee to hold hearings to "reject the spurious claim that environmental protections are the cause of the energy squeeze we see today."[39] Along similar lines, a comment received by the National Coal Council for their report indicated that there were no environmental barriers to installing clean coal technologies. Rather, the comment added that "economic issues are the major barriers, since these technologies are not competitive with either the existing plants/technologies or the combined cycle natural gas-fired plants."[40]

Some studies also challenged the notion that the informal impacts of NSR were distorting the economics of new power plants**.** Testimony by David Hawkins, Natural Resources Defense Council to the House Committee on Science disputed industry claims that either EPA's interpretation of its NSR rules had changed or that such interpretation will prevent expansion of electricity or gasoline production at existing plants. Mr. Hawkins presented a detailed chronology of industry activities which he concluded proved these claims were false.[41] In

---

[36] "New US Coal Plants to Power 20 Million Homes," Reuters, June 5, 2001.

[37] Parker, Larry and Blodgett, John, "Electricity Restructuring: The implications for Air Quality," Congressional Research Service Report for Congress, Updated January 2001.

[38] Schimoller, Brian K., "Balancing Compliance with Competition," Power Engineering, October 1999, page 22-28.

[39] Karey, Gerald, "Environment Should Remain Energy Issue: Protections do not lead to market glitches: Testimony," Platts Oilgram News, April 6, 2001.

[40] "Increasing Electric Availability From Coal-Fired Generation in the Near-Term," The National Coal Council, May 2001. Comment from Manoj Guha (mkugha@aep.com), page 71.

[41] Testimony to the House Committee on Science, May 23, 2001

another hearing, the Executive Vice President of TVA stated that he believed the implementation of NSR programs had not discouraged improvements in efficiency.[42]

Have utilities and developers responded to the changes in economics of new plants brought about by NSR?

The survey of the available literature on NSR, which is sparse, does not conclusively indicate whether power plants responded to changes in the economics of new plants caused by NSR. There is some evidence that power plant owners have internalized the impacts, but whether that led to changes in economic behavior is unclear.

One study examining the interplay between environmental regulations and deregulation concluded that as power plant owners gained experience in complying with environmental regulations, business acumen was being sharpened. Using the Big Bend power plant owned by Tampa Electric Company as a case study, the report argued that successful power plant owners had skillfully adapted the requirements of environmental regulations to deregulated electricity markets.[43]

Most trade press reports announcing new construction quote power plant managers as being attentive to the physical issues (e.g. zoning restrictions, fuel supply source, grid access, water availability) related to new plants.[44] At the same time, most companies announcing new power plants normally include a statement about how the plant provides an environmentally superior source of electricity. In some instances, like with the Athens power plant in New York, plant owners have responded to public opposition by making physical or site adjustments to the design of power plants.

Review of Public Statement and Reports

Background

This section examines the extent of planned capacity expansion in the electric generating sector. ICF Consulting reviewed public statements made by electric generating companies regarding plans for capacity expansion over the next 5 years. SEC filings (10-Ks), annual reports, company press releases, and newspaper, magazine, and specialized journal articles also were examined. To provide context and background, projections of capacity requirements and summary information on planned additions also were reviewed.

With electricity demand increasing, increased generating capacity is needed to maintain the balance between supply and demand. The National Energy Policy report states that U.S. electricity demand is projected to grow 1.8 percent a year over the next 20 years, requiring an addition of 393,000 MW of capacity.[45] To meet this projected demand, the report states that between 1,300 and 1,900 new power plants must be built over the next two

---

[42] Testimony to the Senate Environmental and Public Works Subcommittee on Clean Air, Wetlands, Private Property and Nuclear Safety, February 28, 2000.

[43] Schimmoler, Brian K., "Balancing Compliance with Competition," Power Engineering, October 1999, page 22-28.

[44] Numerous trade press reports. One good source is: Gillete, Becky, "Power Plant Construction in Mississippi Has Major Economic Impact," Mississippi Business Journal, January 31, 2001, page 12.

[45] National Energy Policy Development Group. "National Energy Policy", May 16, 2001, p 1-4.

decades.[46]The U.S. Energy Information Administration (EIA) also projects a need for an additional 96,000 MW by 2005 and 231,000 MW (cumulative) by 2010.[47]

Estimates on planned electric generation expansion vary greatly by source and change over time as corporate plans change. Aggregate expansion estimates vary; indeed, reports and press statements from the same company can change over time. The ICF report presents findings on an aggregate national level and for a selection of individual companies and specific fuels. A study performed by MSB Energy Associates on behalf of the Clean Air Task Force estimated proposed new gas-fired capacity by 2004 to range from 158,000 MW to 165,000 MW for the area covered by the study, which included projects within the Eastern Interconnect[48] and ERCOT [49]. Duke Energy states in its *Year 2000 Overview* that U.S. consumers will demand more than 200,000 additional MW of capacity – nearly a 25 percent increase – within the next decade.[50]

Summary of Selected Announcements of Expansion Plans

A review of public statements in journals, press releases, and corporate annual reports revealed expansion plans on the part of many major U.S. electric generating companies. Data were not readily available for all major generators, but the data for many companies are summarized and presented in this section. Companies give forward looking corporate plans in varying levels of detail (e.g., some by subsidiary, some only for the holding company, with and without indications of time frames). Where available, current generating capacity data are provided. A summary of findings is summarized below in Figure 12.

Figure 12: Summary of Selected Planned Development Activities Based on Public Statements

Parent Company	Subsidiary	Current Capacity (MW)	Capacity Under Development (MW)
Calpine Corp		5,850	29,000
Duke	North American Wholesale Energy	9,000	23,000
PSE&G		10,000	14,000
PG& E Corp	National Generating Group	7,000	10,000

[46] National Energy Policy Development Group. "National Energy Policy", May 16, 2001, p.xi.

[47] US Energy Information Administration (EIA). Annual Energy Outlook 2001 with Projections to 2020, Table A9 Electric Generating Capability. http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_base.pdf

[48] Deisinger, Chris. "The Current Surge of Independent Power Development", MSB Energy Associates, July 10, 2000. http://www.msbnrg.com/MSB-_PEC_White_Paper.html#AppendixA.

[49] The North American bulk power system includes three major transmission interconnections or grids: ERCOT (which encompasses a large part of Texas), the Western Interconnect (which includes most of the Western States), and the Eastern Interconnect (which includes the Midwest, Southern, and Eastern States, and parts of Canada).

[50] Duke Energy Year 2000 Overview. http://media.corporate-ir.net/media_files/NYS/DUK/reports/2000ar/overview.htm

Mirant		20,000*	9,000
Dominion		19,000	9,000
Constellation Energy Group	Constellation Energy Services	9,000	9,000
FPL Group	FPL Company	17,700	6,000
FPL Group	FPL Energy	4,100	2,700
NRG Energy, Inc.		15,000	5,515
AES Corp		10,500	3,500
Reliant Energy		9,231	2,766
Cinergy	Cincinnati Gas & Electric Company and PSI Energy, Inc	21,000	1,700
Note: This table is not exhaustive but illustrates the expansion plans of selected companies based on public statements.			
*Global capacity			

Fuel Types and New Capacity

Planned new facilities are predominantly natural gas-fired plants, but some new coal-fired capacity expansion also has been announced. The companies cited in the previous section of this report made expansion announcements predominantly about new gas-fired units. However, a recent article reported that 34 new coal-fired plants, amounting to approximately 20,000 MW, are being planned for construction over the next 12 years.[51] Many of these plants are reportedly planned for large coal mining states, particularly Wyoming and Kentucky.

According to EPA's Office of Air Quality Planning and Standards, a PSD permit has been granted for 2 new coal-fired boilers as part of a 1000-1600 MW plant in Arkansas scheduled to come on line in the near future. EnviroPower of Indiana, LLC has two permit applications under review for 2 250 MW coal-fired boilers. Kentucky has 5 coal-fired boilers, ranging in capacity from 110 MW to 1,500 MW, for which permit applications are under review.[52]

As noted in the background section at the beginning of this document, if a major modification occurs at an existing power plant, that plant becomes subject to NSR. The regulations governing which actions at

[51] "New U.S. Coal Plants to Power 20 Million Homes". Reuters, June 5, 2001.

[52] Response to STAPPA/ALAPCO Questions to State and Local Officials on Mercury Utility Boiler Emissions Test Data, STAPPA/ALAPCO, May 15, 2001.

existing sources trigger new source review requirements are complex, and involve making distinctions between routine and non-routine maintenance, and in calculation of emissions prior to and after changes are to be made. As a result, it may be appropriate to examine whether repairs that restore lost capacity and component upgrades that improve efficiency may be discouraged by NSR. It may also be appropriate to examine the extent to which NSR rules concerning the modification of existing facilities promote or deter investment in new utility and refinery generation capacity, energy efficiency, and environmental protection. Some have argued that the modification rule deters modifications at existing plants, especially where the emissions increase is significant, but the increase in generating capacity is not.

In a report to the Secretary of Energy[53], the National Coal Council (NCC) examined data in the North American Electric Reliability Council's GADS database, and found that coal-fired units over 20 years of age (approximately two-thirds of total coal-fired generating capacity) had been substantially derated, compared to units less than 20 years of age. The NCC concluded that: "If all existing conditions resulting in a derating could be addressed, approximately 20,000 MWs of increased capacity could be obtained from regaining lost capacity due to unit deratings." The NCC further stated that: "These approaches and techniques could only be logically pursued by the facility owners if it was clearly understood that the increased availability and/or electrical output would not trigger New Source Review (NSR) and if repowering or construction of new clean coal technologies would be subject to the streamlined permitting authorized by the 1990 CAA Amendments."

6. NSR Impacts on Energy Efficiency Improvements

Electricity generators often have opportunities to improve their generating efficiency. One measure of such efficiency is the amount of electricity generated per amount of fuel consumed. The reduced cost of fuel per megawatt generated provides a strong economic incentive to make such improvements. On a megawatt basis, such changes also reduce pollution (though if a generator uses the more economical, upgraded unit more often as a result, total emissions can still increase). Another measure of efficiency is the amount of electricity generated per unit of emissions. EPA did not find any research specifically addressing how the NSR program impacts generators' ability to make these types of changes. However, a number of issues have been raised recently by industry in the context of specific projects.

One example is a case raised by Detroit Edison. The company proposed to replace and reconfigure the high-pressure section of two steam turbines at its Monroe Power Plant. The purpose of this proposed project was to upgrade energy efficiency. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Yet because this proposed project would result in substantially improved efficiency compared to the original design, EPA considered it a physical change under its NSR regulations, and if it were to result in a significant increase in emissions, the units would be subject to NSR. It has been asserted that this decision will lead to less investment in efficiency improvements as opposed to the normal replacement of the damaged blades. However, no specific information is available on how the costs of NSR (e.g.,

[53] National Coal Council, Increased Electricity Availability From Coal-fired Generation in the Near-Term, p.9, May 2001.

control technology, permitting expense, etc.) alter the economics of the project, or whether they make the project no longer economically attractive. Nor is information available regarding the extent to which this kind of project would or would not increase emissions.

Another example is combined heat and power (CHP) units, which can be used to replace existing industrial boilers. They can provide both steam to the industrial facility and electricity to the public. They emit significantly fewer emissions than the existing boilers they replace. Because of how NSR regulations define a single source, power companies assert that these facilities are not being brought on line in greater numbers. There is also the assertion that NSR may cause CHP operation for small plants (e.g., 15 MW or less capacity) to be uneconomic.. Absent the complicated NSR requirements, the companies claim that many older, higher emitting boilers would be replaced by these more efficient units. Again, no specific information is available on the relative effect of NSR on the overall viability of such projects.

The final example of how NSR allegedly hinders efficiency improvements in electrical generation is the use of foggers. Duke Power proposed a project that involved the installation of inlet air foggers on combustion turbines (CTs) at the Duke Power Lincoln Combustion Turbine Facility. Duke Power, which operates 16 simple cycle CTs at the Lincoln facility, proposed to install inlet air foggers on each CT to increase power output during periods of high ambient temperatures. Use of foggers allows combustion of additional fuel and, thus, greater power output at the same ambient temperature. Despite more fuel combustion, the possibility exists that nitrogen oxides emissions actually decrease when foggers are turned on. The project was considered a physical change under NSR regulations, and appropriate safeguards were required to ensure that the emissions did not significantly increase as a result of the change. It is claimed that this decision makes it harder to use the foggers and increase the output of existing units.

A May 2001 report by the National Coal Council [54]discussed the impact of regulatory policy on efficiency improvements at existing coal-fired power plants. The report stated, "EPA has further indicated that it will treat innovative component upgrades that increase efficiency or reliability without increasing a unit's pollution producing capacity as modifications as well. EPA's current approach to these projects strongly discourages utilities from undertaking them, due to the significant permitting delay and expense involved, along with the retrofit of expensive emission controls that are intended for new facilities. This is the greatest current barrier to increased efficiency at existing units." To support this conclusion, the NCC identified two EPA determinations, one involving Detroit Edison Company in May 2000 (discussed above), the other involving Sunflower Corporation in 1998, in which EPA ruled that improved, higher efficiency turbine blades could not be used to replace less efficient blades that had broken, without invoking new source review and associated costs for additional pollution controls.

III. Petroleum Refining Industry

1. Historical NSR Permitting Data

[54] National Coal Council, Increased Electricity Availability From Coal-fired Generation in the Near-Term, p.9, May 2001.

This section presents a summary of the available data for NSR permitting for the refining industry. As described above for the utility sector, most of the available information about NSR permitting comes from the EPA Regional Offices. Limited data are available for refineries, because only a small number of permits have been issued for this sector. For this report, only PSD data were used, because sufficient nonattainment NSR information is not available. A review of PSD permit data found that there have been 11 PSD permits issued involving refineries since 1997. All of these permits were for modifications at existing refineries. The average permitting time from application to issuance was 5.2 months. Information is not available to determine the increase in refining capacity as a result of these PSD permits. However, information presented later in this section discusses overall capacity trends in the refining industry.

Refinery Enforcement Actions

Based on investigations conducted over the past 4 years, EPA and several states have taken enforcement actions against owners and operators of several refineries alleging that modifications were made at a number of U.S. refineries that should have undergone NSR permitting.

For example, refineries have undertaken a variety of projects to increase the capacity of fluid catalytic cracking units (FCCUs):

Increasing or modifying the air flow to the FCCU regenerator, resulting in an increased coke burn rate and increased emissions;

∀ Modifying slide valves to increase catalyst circulation and throughput, but also increasing coke burn and emissions;

∀ Increasing wet gas compressor capacity;

∀ Modifying risers and/or feed distribution systems;

∀ Installing more/larger cyclones and/or overhead gas coolers; and

∀ Rebuilding/replacing the FCCU regenerator or the reactor.

EPA has gathered data from 13 companies with 48 plants. EPA filed notices of violation of NSR for eight refineries. For five of the refineries, the refinery obtained a minor NSR permit based on what EPA believes were incorrect estimates that concluded there were no emissions increase resulting from changes at the refinery for at least one of the actions cited in the notice of violation. EPA brought enforcement actions against owners and operators of new units based upon the failure to go through NSR (e.g., for the construction of new crude and vacuum distillation units or the reuse of a sulfur recovery unit from another refinery), improper netting analyses, and the provision of erroneous emissions information.

To date, EPA has reached four company-wide settlements with the following companies: Koch, BP-Amoco, Motiva/Equilon/Shell, and Marathon Ashland Petroleum. These settlements involve 27 refineries and approximately 29 percent of domestic refining capacity (4,760,000 barrels per day). The estimated cost of implementing the control equipment aspects of all of the consent decrees is $1.3 billion. EPA estimates that these settled cases alone will reduce NOx emissions by 43,200 tons per year (tpy) and SO2 emissions by 88,250 tpy. EPA also is engaged in company-wide settlement negotiations with additional companies.

2. Factors Affecting Investment in New Capacity

This section summarizes available data on how executives in the refining industry make decisions on whether or not to invest in new refining capacity. These data are the result of a literature search, conducted by ICF Consulting, Inc., of 35 sources of information from 19 industry, trade, and financial publications from 1971 to 2001. ICF then summarized factors affecting corporate decisions, which are presented here in order of relative importance according to the literature.

A decision to invest in new refining capacity or expand an existing refinery requires simultaneous evaluation of strategic and siting considerations and permitting issues. Refining company executives in general are responsible for ensuring the financial health of the corporation and providing a rate of return (ROR) on investment that is acceptable to investors. Company officials and developers typically do not enumerate the relative importance of different factors in evaluating projects. Rather they seek to identify the impact of all the different elements on the ROR of each potential investment option. An investment's ROR is the most common metric by which investors organize, standardize, and evaluate all pertinent information in order to make an informed investment decision. Although decision makers often rely on ROR projections to make investment decisions for a new plant or for expansion of existing facilities, they remain sensitive to intangibles such as public opinion.

In general, there are three primary considerations in project investment decisions:

1. Strategic Considerations: whether a market that a refinery will furnish products to is likely to be most profitable for operations.

2. Siting Considerations: proximity to a pipeline system for transporting products, water availability, as well as local environmental and zoning issues.

3. Permitting Issues: time and cost of obtaining various permits, including air and operating permits, and the impact of public opinion on the permitting process for the new or expanded facility.

Strategic considerations. Strategic factors generally have the most impact on ROR. Capital outlay, energy prices, and production costs all have a large impact on ROR; in addition, uncertainty about prices and costs introduce risk in the investment decision. The other notable component of strategic considerations is environmental costs, primarily pollution control equipment. Such usually have a small to moderate impact on ROR.

Changes in fuel specifications (for example, as a result of government regulation of fuel or to meet voluntary industry standards) can trigger investment in new refining capacity. While refinery changes required to meet new fuel specifications generally do not increase capacity, they often can lead to voluntary decisions to increase capacity at the same time, because costs are lowered when capacity expansions are undertaken at the same time as other changes.

Similarly, investment in new capacity at petroleum refineries always has depended upon on the costs of crude oil and moving refined products to markets. Over the past 10 to 20 years, national and worldwide crude oil production centers have changed. Thus, proximity to foreign oil sources has a more pronounced role in product distribution decisions. For example, in one of the few cases where serious consideration was given to building a green field refinery (Williams Company's 18-month study of a possible Phoenix, AZ, refinery), one key factor that adversely impacted the project was the announcement of a new refined product pipeline that would link major refining centers in the California Bay area, San Joaquin Valley, and Los Angeles with Arizona and southern Nevada markets.

The relatively low cost of pipeline product movement favors large-scale refining centers over smaller niche market refineries, because the distant competitors' advantage in lower-cost production is not significantly reduced by the cost of product movement.

An additional factor influencing investment decisions is technology. Petroleum refining is one of the most technology-intensive industries, and refining technology is becoming more intensive and more expensive. Technology upgrades are economically difficult to recover in a flat marketplace. However, expansion of capacity and increased market share enhance the economics of technology conversions, because it leads to increased revenues.

Still another factor influencing investment decisions is the changing cost of expanding capacity. Many factors influence expansion costs, but the literature reveals one particularly interesting change – the availability of used refinery assets. As financially weaker refineries close, they sell their assets at from 3 - 10 percent of the cost of a new refinery. Furthermore, a closing refinery tends to enjoy local advantages – e.g., nearby support industries, skilled workers, and tax subsidies – that a green field location would not necessarily have. Buying and selling refineries and refinery assets has emerged as a very cost-effective way to enter or remain viable in the refining business.

A minor factor affecting the cost side of the investment decision is the cost of compliance with environmental regulations. All refineries are subject to nearly the same requirements, although their generally fixed costs tend to be smaller for a large refinery than for a small one. Pollution control costs are passed along in the price of the products. The literature search revealed only 5 references to pollution abatement issues, and no specific references to NSR, as factors influencing decisions to invest in new capacity.

Siting considerations. The literature search discovered only one decision that addressed siting a new greenfield refinery. The key factors in this decision appeared to be based on economics, product movements, and alternative options to buy an existing refinery. Similarly, decisions on whether to expand refinery capacity were clearly tied to the prospect of future profitability in the market.

According to the literature review, many refineries have closed since 1990 for various reasons, e.g., limited operating flexibility, inability to meet demand shifts, lack of capital needed to comply with environmental and anti-dumping rules, and low market demand for heavy oil products. Other factors that have affected profitability include: unusually warm winters, which dampened the heating oil market; low demand in 1991 due to economic recession; and decreasing gross margins. However, these factors continue to change over time. For example, refining margins were at record highs last summer, and high margins are continuing. Furthermore, refinery closures open product markets for larger, more profitable refineries. These newly opened markets create an incentive to increase capital intensity if there is an increase in profit per unit of output.

Permitting Issues. The literature search revealed only 5 references to pollution abatement issues, and no specific references to NSR, as factors influencing the decision to invest in new capacity.

3. Trends in Capacity and Utilization

This section summarizes the available data on trends in refinery capacity expansion and utilization. Existing data reveal that no new refineries[55] have been built in the United States in the past 20 years, and the number of existing refineries has fallen from 324 in 1981 to 149 in 2000. The decline in refineries in the early 1980s is due largely to removal of economic regulations that had previously had the effect of supporting small refineries. Between January 1, 1981, and January 1, 1984, 111 small refineries shut down. (Of these 111 refineries, 52 had operated for less than 10 years, many of them for only one to two years.) These data appear to support the argument that price controls and supply allocation resulted in the proliferation of small inefficient refineries. These refineries were unable to survive following deregulation, and probably would not have been built if regulations had not been in place.

Apart from the deregulation of the early 1980s, the data reveal a slower decline in the number of refineries. However, as the data show, total refinery capacity has increased over this period. Figure 13 provides data on the number and capacity of U.S. refineries from 1986-1999. The remainder of this section focuses on data from this time period, so that the effects of deregulation do not drive the results.

Figure 13: Number and Capacity of Total U.S. Operating Refineries (1986 – 1999)

Year	Number of Operating Refineries*	Atmospheric Distillation Capacity for Operating Refineries (MMbpcd)	Mean of Atmospheric Distillation Capacity for Operating Refineries (Bpcd)	Median of Atmospheric Distillation Capacity for Operating Refineries (Bpcd)
1986	189	14.94	79,050	46,200
1987	190	15.02	79,042	46,100
1988	186	15.01	80,709	48,250
1989	188	15.06	80,120	48,000
1990	178	14.96	84,038	53,500
1991	177	14.97	84,551	55,000
1992	168	14.78	87,958	56,750
1993	164	14.70	89,663	57,750
1994	159	15.08	94,853	62,500
1996	152	15.17	99,789	65,000
1998	149	16.06	107,795	72,500
1999	149	16.31	109,496	73,000

*The number of refineries column only accounts for those refineries with operating capacity on each given year. All subsequent graphs presenting number of refineries use this data.

Source: Energy Information Administration

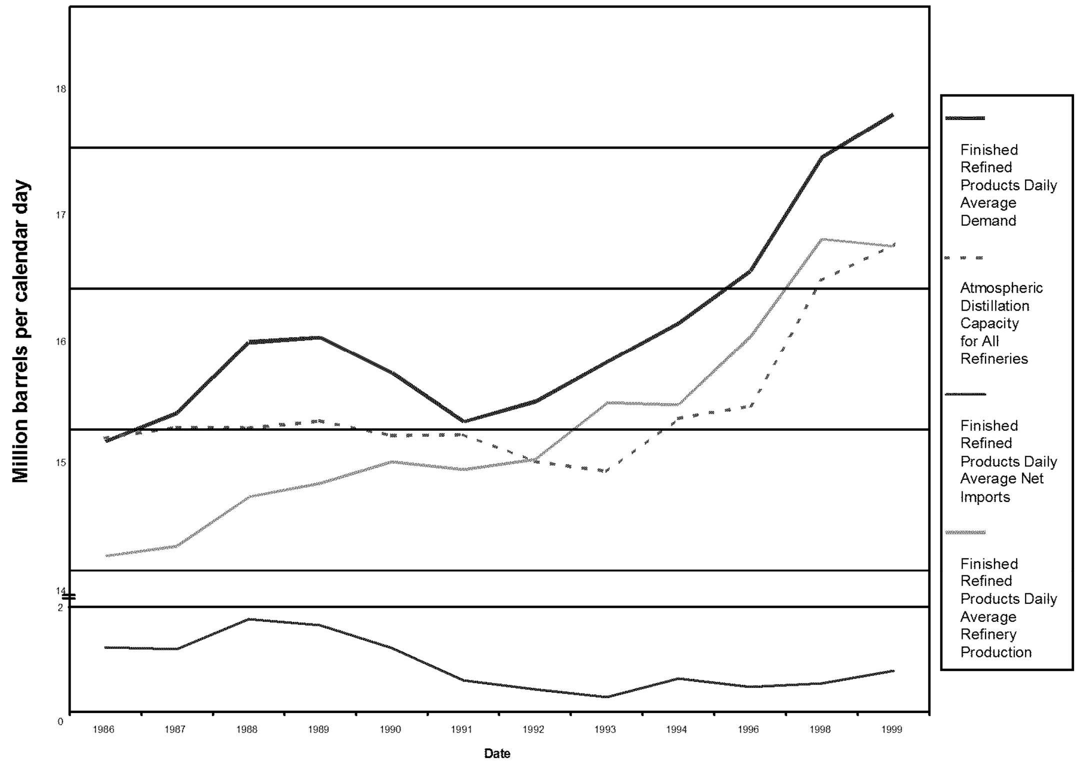
[55] Although no new greenfield refineries were built in the U.S. during this period all surviving U.S. refineries have been substantially rebuilt and revamped.

From 1986 to 1999 the number of U.S. refineries continued to decline, but the atmospheric distillation capacity (and other downstream capacities) continued to increase. Capacity creep maintained and increased overall capacity, despite the closures[56]. Large, efficient Gulf Coast refineries were able to take advantage of technological economies of scale to expand capacity while other refineries shut down. Between 1984 and 1999, 64 refineries shut down, 29 of them between 1990 and 1996. Most of the plants that shut down were smaller, simpler plants. Many of them filled a niche market or depended on the market for heavy fuel oil. Unfortunately, they were entering a period when growth was occurring in the demand for light products, and especially those with stringent specifications. In addition, in the latter part of the period many of the smaller refineries came under increasing pressure and competition from the large, efficient Gulf Coast refiners.

As shown in Figures 13 and 14, during the time period 1986 – 1999 the overall atmospheric distillation capacity of U.S. refineries grew. The increase in the closures and the temporary fall in capacity in the early 1990s were due to steadily decreasing prices, worldwide recession, and the resulting fall in demand. However, 1994 saw the recovery of demand and the steady growth of capacity additions. The remaining data in Figure 13 show the impact of economies of scale on the industry, driven in part by technological innovations. The average size of U.S. refineries grew steadily over this period, from approximately 79,000 barrels per day in 1986 to nearly 110,000 barrels per day in 1999. The median size also increased from about 46,000 barrels per day to 73,000.

[56] Capacity creep is the accumulation of incremental capacity increases from normal optimization of refinery facilities and processes (e.g., installing bypass piping where flow bottlenecks exist).

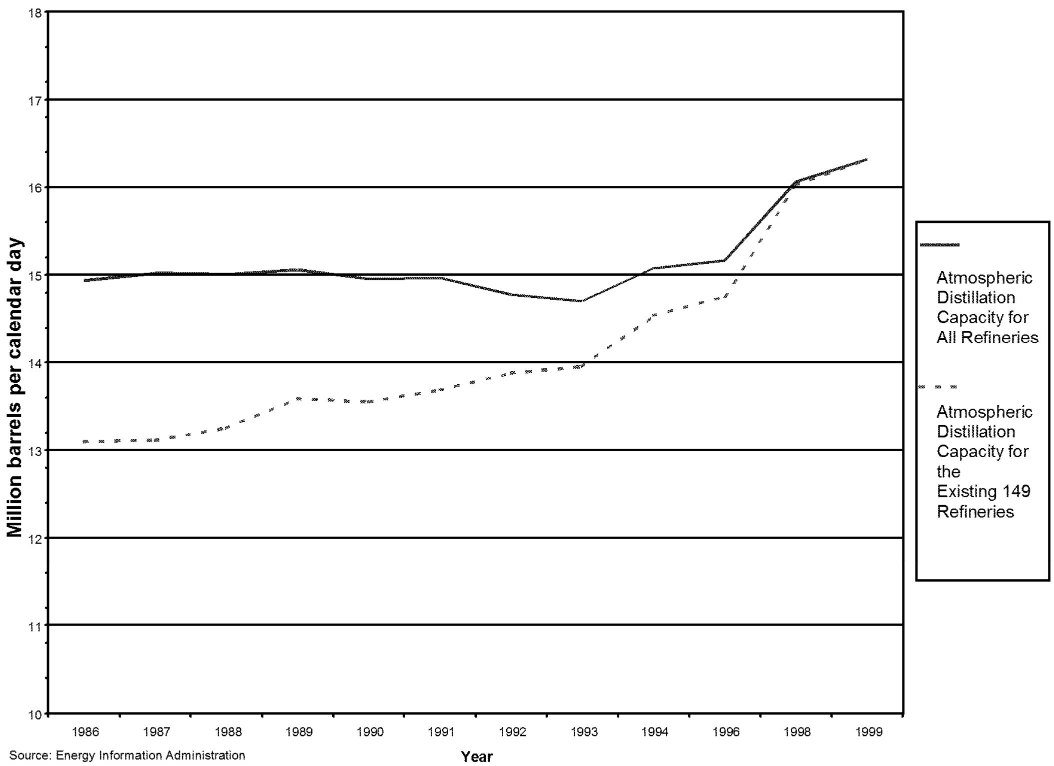
Figure 14: Total U.S. Atmospheric Distillation Capacity and Daily Average Supply and Demand of Finished Products (1986 to Present)



Source: Energy Information Administration

ED_001598_00028214

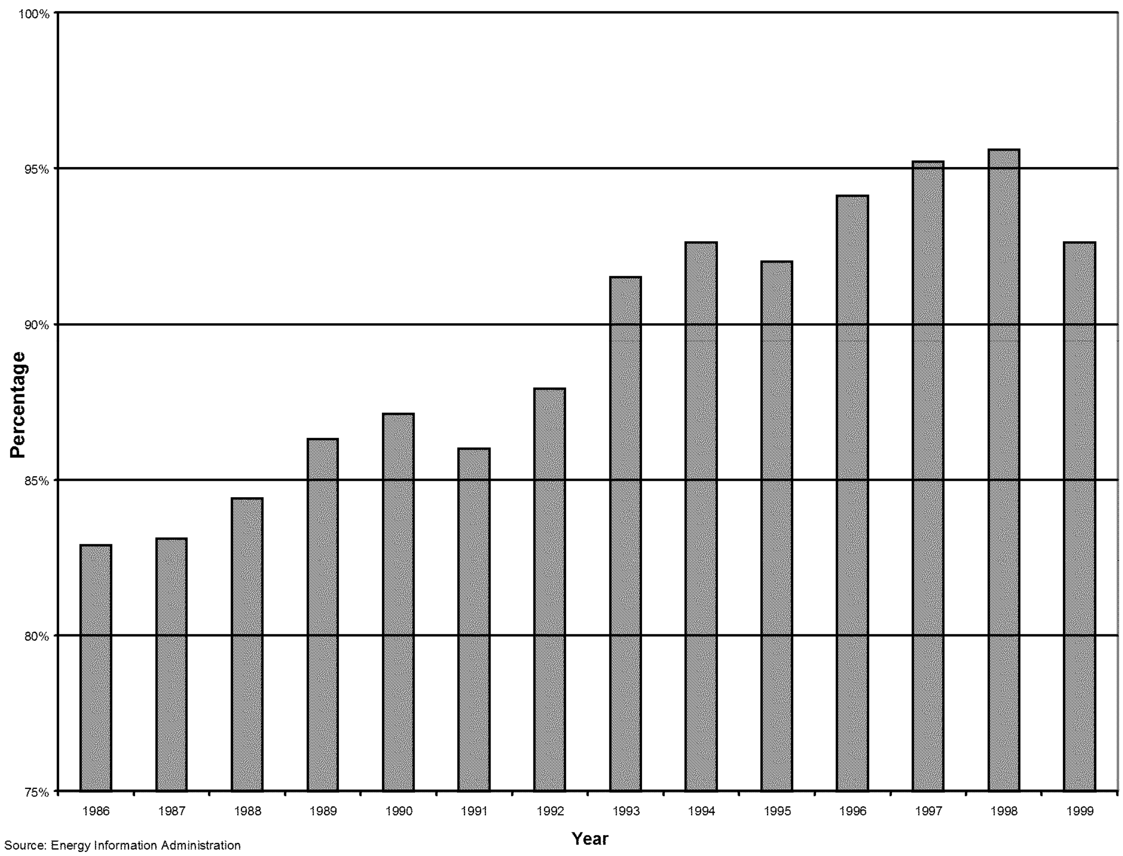
Figure 15: Atmospheric Distillation Capacity for Total U.S. Refineries and Surviving 149 Refineries (1986 to Present)



ED_001598_00028214

Finally, Figure 16 shows the annual average capacity utilization for all U.S. refineries over the period. Utilization is measured by EIA as the atmospheric distillation capacity. There are some data available on the utilization of the downstream processing units, and that typically is also very high. Capacity utilization generally has increased during this time. The early years on the figure reflect some excess capacity and decreases in demand driven by economic downturns. However, the figure also clearly shows the effect of growing demand in the later years driven by increased economic growth.

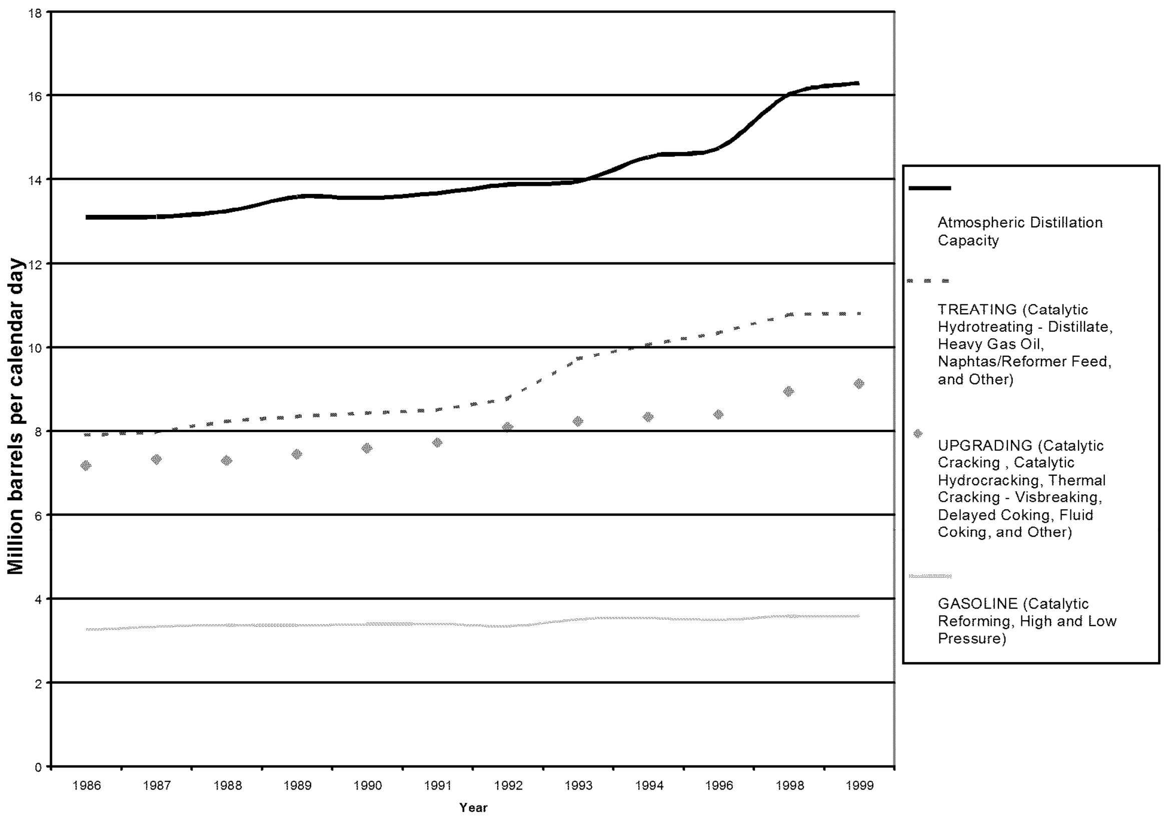
Figure 16: Total U.S. Refinery Utilization (1986 to Present)



Source: Energy Information Administration

ED_001598_00028214

Figure 17: Downstream Processes Capacity for 149 Refineries in Continuous Operation from 1986 to Present

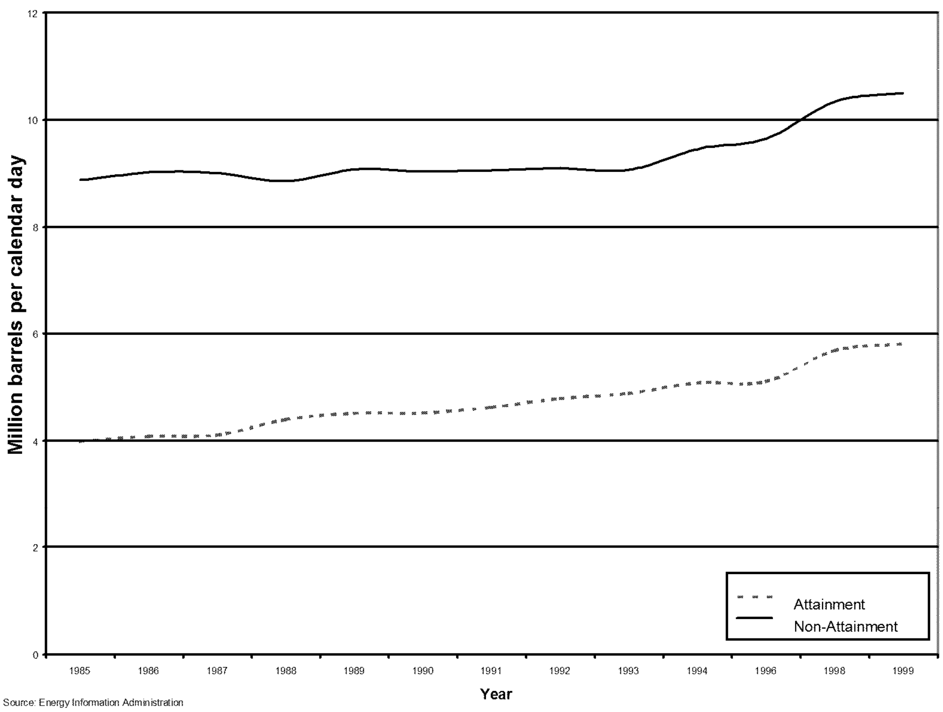


Source: Energy Information Administration

Figure 15 compares the atmospheric distillation capacity for all operating U.S. refineries to that of the surviving 149. As can be seen, the capacity of the 149 surviving refineries increased steadily over time. Figure 17 shows the growth of downstream processing capacity over time for these same 149 refineries. As Figure 17 shows, capacity, particularly for sulfur treating processes, has increased along with the overall increase in atmospheric distillation capacity. Capacity for upgrading heavy products (i.e., fuel oil) to light products (i.e., gasoline) continues to increase.

Figure 18 shows capacity for the 149 refineries divided between those located in attainment and non-attainment regions. Capacity is higher in nonattainment areas, as refineries tend to be clustered in high-population, industrialized areas with poor air quality. However, the rate of incremental growth is approximately the same whether in attainment or nonattainment areas, indicating that this is not a determining factor in investment in new capacity.

Figure 18: Atmospheric Distillation Capacity for Attainment and Non-Attainment Regions for 149 Refineries in Continuous Operation from 1986 to Present



Source: Energy Information Administration

ED_001598_00028214

4. Data on Costs of Pollution Controls

The purpose of this section is to provide an understanding of the relative importance of air pollution control costs relative to the cost of new refineries[57] and to the cost of capacity expansion at existing refineries. A review by ICF found data and information sources related to this issue to be limited. The Bureau of the Census collects data on pollution abatement expenditures whose primary purpose is environmental protection. (Some expenditures, such as investments in a catalytic process, have pollution abatement benefits but their primary purpose is to increase the yield and quality of a refined product).[58] Air pollution control costs are included here, but so are other pollution abatement expenditures, such as research and development and operating, maintenance, and direct administrative expenditures for legal fees, operating permits, restoration of sites, and Superfund taxes. The American Petroleum Institute (API) collects similar information – although it does not include the primary purpose qualifier – in a voluntary survey known as the Environmental Expenditures Survey (EES)[59] No data were available on the specific costs of compliance with NSR.

With respect to overall capital costs in the petroleum refining industry, there are two sources of data: the Bureau of the Census' 1997 Economic Census on Petroleum Refineries, and the Energy Information Administration's Financial Reporting System (FRS). The Economic Census collects data on total capital expenditures (new and used) for (1) permanent addition and major alterations to manufacturing establishments, and (2) machinery and equipment used for replacement and additions to plant capacity if they are of the type for which depreciation accounts are ordinarily maintained.[60] Exhibit 16 of the ICF report has a detailed listing of this data for annual estimates prepared for the years 1190 –1999.

The EIA's FRS is an annual survey that collects financial and associated operating information from the top 24 U.S.-based major energy-producing companies. The data are reported on a line-of-business basis, including the U.S. petroleum refining and marketing line of business. The FRS companies make up a major part of the U.S. refining industry. For example, from 1990 to 1995, the FRS companies' share of U.S. crude distillation capacity has ranged from 66 percent to 69 percent.[61]

An EIA report entitled *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (October, 1997) incorporated FRS capital expenditures and the API and Census pollution abatement data into one

[57] Although no new green field refineries were built in the U.S. during this period all surviving U.S. refineries have been substantially rebuilt and revamped; therefore, this section will focus entirely upon capacity expansion.

[58] If a technology's primary purpose is for the reduction of air pollutants, then it is listed as an air pollution abatement expenditure. But not all pollution abatement technologies are classified as abating a particular pollution category, like water, air, and solid/contained waste. Because of these difficulties, an analysis of pollution control technologies and their costs relative to particular air pollutants using census data has some limitations.

[59] American Petroleum Institute, Comparison Between the 1990-1993 API's Environmental Expenditures Survey and The Bureau of the Census' MA-200, Hazem Arafa, July 5, 1995.

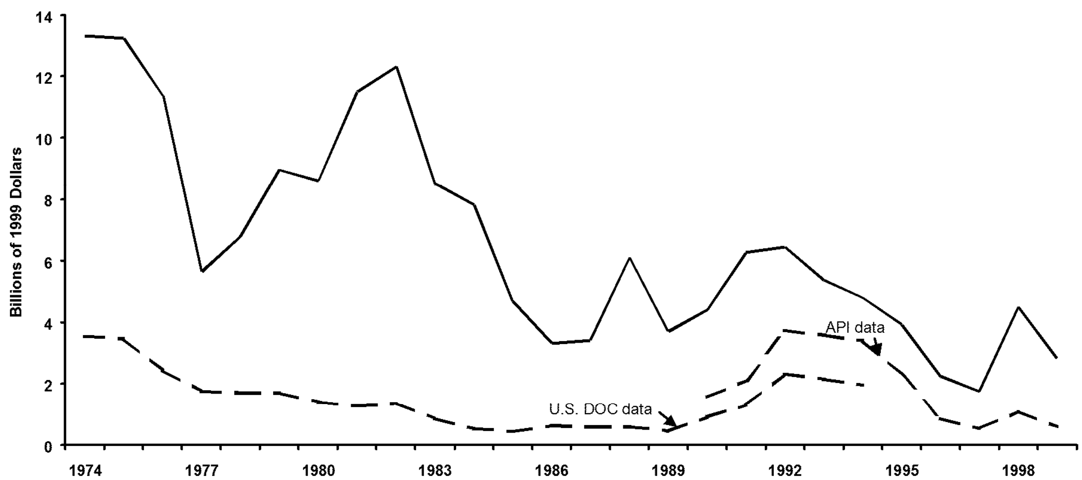
[60] U.S. Department of Commerce, Economics and Statistics Administration, The Bureau of the Census, *1997 Economic Census, Manufacturing, Petroleum Refineries*, September, 1999.

[61] The U.S. Department of Energy, Energy Information Administration, Office of Energy Markets and End Use, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability*, October, 1997.

complete analysis of this question. This report concluded that approximately 7.6 cents of the $1.52 ($1995) per barrel decline in refining and marketing net cash margins between 1988 and 1995 was due to increased operating costs traceable to pollution abatement. Further, EIA concluded that of the 12 percentage point decline in the return on investment to major U.S. refining/marketing operations, slightly over one percentage point can be attributed to increased capital expenditures and operating costs for pollution abatement.[62]

Figure 19 shows the FRS companies' capital expenditures adjusted for inflation. The data show that, over time, capital expenditures for pollution abatement have accounted for a varying share of total capital investment, which was highest after the Clean Air Act amendments of 1990, but has diminished noticeably in recent years. The data also show that, despite varying pollution abatement expenses, a significant portion of capital investment is attributable to other areas, such as capacity expansion.

Figure 19: Refining Capital Expenditures and Pollution-Related Capital Expenditures



Sources: Overall refining capital expenditures: Energy Information Administration, Form EIA-28 (Financial Reporting System)

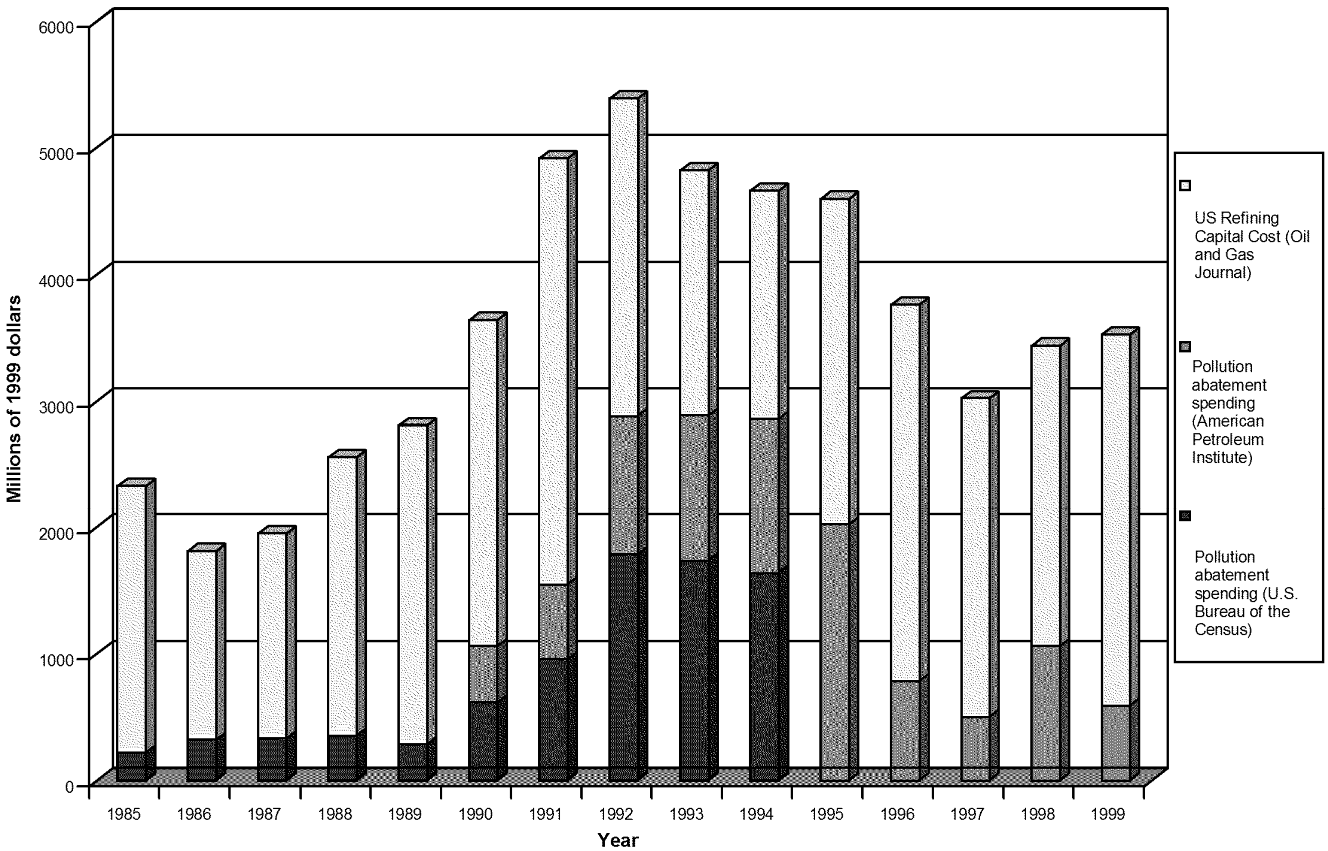
Pollution-related capital expenditures: 1974-1994: U.S. Department of Commerce; 1990-1999: American Petroleum Institute, *U.S. Petroleum Industry's Environmental Expenditures, 1990-1999* (Washington, DC, January 19, 2001).

Figure 20 shows a similar picture using a bar graph and total capital expenditure data from the Oil and Gas Journal.[63] The same conclusions can be drawn from this exhibit, which shows increased pollution abatement expenditures in the early to mid-1990s. It must be noted that API's pollution abatement spending is greater than the Census' pollution abatement spending in all years for which data were available for both sources (1990-1994). Therefore, the shaded API areas are represented as the difference between total API data and U.S. Census data.

[62] Ibid.

[63] Oil and Gas Journal, *Capital Spending Outlook*, various issues.

Figure 20: Historical U.S. Refining and Market Investments



<u>Sources</u>: Oil and Gas Journal - *Capital Spending Outlook*, U.S. Bureau of the Census - *MA-200*, American Petroleum Institute - *Environmental Expenditures Survey*

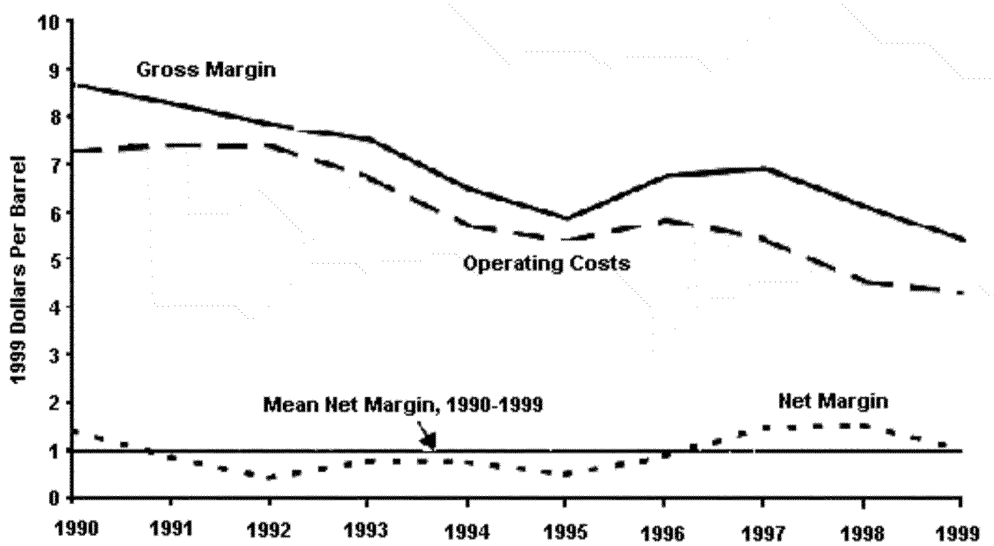
Note: The shaded API areas in 1990-1994 are represented as the difference between total API data and U.S. Census data. Therefore, API data is greater in all common years.

ED_001598_00028214

5. Data on Refinery Profitability

The last two decades have seen considerable volatility in refinery profit margins. The gross margin peaked in 1980; since deregulation, it has generally decreased, as have operating costs. Net margins have followed the same pattern, with the mean net margin being $1 per barrel in 1999 dollars (from Exhibit 19 of the ICF report). NPC data, which cover a longer period, show net margin as negative in the mid-1980s.

Figure 21: U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies (1990-1999)



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Figure 21 does not reflect the most recent data on margins, which are likely to increase substantially over 1999 data. Exxon-Mobil profits in the first quarter of 2001 were up over 51percent to $5.1 billion, Conoco was up 58 percent to $616 million, Chevron was up 53 percent to $1.6 billion, Texaco reported a 45 percent increase to $833 million in profits, and Phillips Petroleum was up 86 percent to $504 million

6. NSR Impacts on Capacity Additions

ICF conducted a series of directed literature searches seeking information on the impacts of NSR on refinery capacity. The review included approximately two dozen sources.

No studies were found specifically mentioning NSR's impact upon refinery expansion. However, many articles discussed NSR's impact on related issues that directly affect the expansion or changes at refineries, in particular, costs and technologies employed. Another group of studies either mentioned general regulatory effects on factors directly affecting capacity expansion, or that related to NSR but with no mention of capacity expansion.

The National Petroleum Council (NPC) reported in June 2000 on the ability of the Nation's petroleum refining and distribution infrastructure to deliver adequate petroleum supplies to consumers, given a number of recent regulatory initiatives requiring cleaner or better performing transportation fuels.[64] The NPC concluded: "The most critical factor in the U.S. refining industry's ability to meet new fuel requirements in a timely manner is the ability to obtain permits." Moreover, the NPC report noted the lengthy process for obtaining such permits and explained how that process could conflict with the relatively near-term need for improved, cleaner transportation fuels. The permitting steps outlined by NPC included:

- 3-6 months to prepare a permit application
- 1-3 months for the permitting authority to deem the application complete
- 3-6 months for the development and negotiation of a draft permit
- An unstated period for public notice and the opportunity to receive public comment on the draft permit
- An unstated period of time for the permitting authority to respond to public comments and take final action on the permit

Public statements by some oil company executives and organizations assert that NSR impedes U.S. capacity expansion. Generally, these statements express concern about NSR and other regulations on refinery expansions. Some general concern about recent NSR enforcement actions and their potential impact on expansion also is voiced in the literature. Moreover, specific cost or other decision-making data related to permitting are not directly addressed in the available literature. The search also revealed one positive statement from an environmental interest group about the environmental benefits of NSR at refineries.

ICF also looked at available public statements made by refinery companies regarding plans for capacity expansion over the next five years. Sources included SEC filings (10-Ks), Annual Reports, company press releases, and newspaper, magazine, and trade journal articles.

As a result of time constraints, the literature review focused primarily on a cross-section of the refining companies. 10Ks and annual reports were reviewed for a large integrated (Exxon-Mobil), an independent (Tosco), a medium (Sunoco), and a small (Murphy Oil) publicly owned refining company. Relevant press releases were collected for the largest refining companies, including Exxon-Mobil, BP Amoco, Chevron, Valero, Phillips, Marathon Ashland, Conoco, and Citgo. Article searches on the all-inclusive news database Lexis-Nexis and the Oil & Gas Journal complemented these refinery-specific searches. Other online sources included the Department of Energy's Energy Information Administration and the American Petroleum Institute.

Several companies, through their press releases and 10Ks, have expressed their plans to expand refining capacity:

Citgo, a subsidiary of Venezuela's PDVSA, is studying investments of up to $300 million to expand capacity by 100 Mbbl/d at its Lake Charles, Louisiana, refinery.[65] Furthermore, Venezuela's President Hugo Chafes, during a visit to Texas, announced that Citgo's Corpus

[64] National Petroleum Council, U.S. Petroleum Refining - Assessing the Adequacy and Affordability of Cleaner Fuels, June 2000.

[65] "Citgo to Invest Up to US $300 Million to Increase Refining Capacity." Business News America S.A., April 30, 2001.

Christi refinery, while having plenty of room to grow, has no plans for expansion at this time. Texas State representative Jaime Capelo urged the Corpus Christi and Nueces County community to "see what [it] can do to include Corpus Christi in Citgo's expansion process."[66]

Alon USA, recent acquirer of TotalFinaElf's U.S. assets, reported that it has immediate plans to expand its refineries. Its first goal is to expand the Big Spring, Texas, refinery's crude distillation unit to 75 Mbbl/d. The company plans on reaching the 65 Mbbl/d-stage in 2002.[67]

After recently acquiring UDS, Valero expects to improve its profits by $195 million in the first year after the merger and $240 million in the second year. CEO Bill Greehey mentioned that these additional profits could be used to expand refineries.[68] *Additionally, Valero is planning to expand FCC capacity by 12 Mbbl/d by 2004 at its Krotz Springs, Louisiana, refinery.*[69]

TotalFinaElf's ongoing construction of a steam cracker near its Port Arthur, Texas, refinery, and the need for naphtha as a feedstock for a planned acrylic plant in Atofina's Bayport, Texas, polyethylene plant, will eventually "result in a sizable increase in the size of the [Port Arthur] refinery." According to refinery manager Dale Emanuel, while gasoline is highly profitable, the refinery will focus its attention to the production of feedstock for chemicals and the meshing of the refinery with the nearly completed steam cracker. Additionally, TotalFinaElf recently added a condensate splitter to its refinery, ultimately increasing capacity to around 220 Mbbl/d.[70]

Phillips allocated $246 million of its capital budget to Refining, Marketing, and Transportation. Funds will be used to complete a low-sulfur gasoline demonstration unit (beginning in 2001), a 20 Mbbl/d crude oil capacity expansion (beginning in 2002), and manufacturing automation at its Borger, Texas, refinery. Funds will also be used for environmental projects related to state-mandated emissions reductions at its Sweeney, Texas, refinery.[71] *Furthermore, Tosco's refinery in Ferndale, Washington, will add a 30 Mbbl/d FCC unit to its facilities. This project will be completed in January, 2003.*[72]

Murphy Oil's planned refining, marketing, and transportation capital expenditures in the U.S. for 2001 amount to $145 million. This includes spending on "greener fuel" projects at the Meraux refinery. The main component of the projects is the construction of a hydrocracker and its associated facilities. Furthermore, the company plans to enhance the refinery's crude unit to expand crude throughput capacity from 100 Mbbl/d to 125 Mbbl/d. Completion of this project is expected by mid-2003. Additionally, future plans include investing $25 million to expand sulfur recovery capacity by late 2002.[73]

Chevron plans to invest $600 million in its U.S. refining and marketing sectors. The company "will continue to make investments to improve safety, reliability and profitability in its refining segment."[74]

---

66 "Chavez Denies Dictator Rumors; Venezuelan Chief Also Says Refinery Isn't Due Increase." Corpus Christi Caller-Times., June 3, 2001.

67 "Alon USA – A Counterflow in Investment and Technology." Petroleum Economist Limited., March 31, 2001.

68 "Aiming for No. 1 Valero's Growth Plan Goes Beyond its UDS Purchase." The Corpus Christi Caller-Times., May 13, 2001.

69 *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

70 "Picking Up a Head of Steam; Construction of Huge Plant Nearly Done." The Houston Chronicle., June 8, 2001.

71 *"Phillips' Board of Directors Approves 2001 Capital Budget."* Phillips Newsroom., December 12, 2000.
"Phillips Plans Improvement Project at Borger, Texas, Refinery." Phillips Newsroom., June 6, 2000.
"Phillips to Build Low-Sulfur Gasoline Facility at Borger Refinery." Phillips Newsroom., October 21, 1999.

72 *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

73 Murphy Oil, 10K, Filed March 22, 2001, for Period Ending December 31, 2000.

74 "Chevron Announces $6 Billion Capital Spending Program for 2001." Chevron Press Releases., January 18, 2001.

Equiva Services LLC is planning to expand hydrocracking and hydrotreating capacity at its refineries in Los Angeles, California; Puget Sound, Washington; Port Arthur, Texas; Deer Park, Texas; Norco, Louisiana; and Convent, Louisiana. While the added capacity at each site is still unknown, the company expects completion of the projects by 2003.[75]

ExxonMobil has entered the engineering phase of their project to revamp hydro-desulfurization units at the company's Baytown, Texas, refinery. The project, which is expected to be completed by 2002, will add 133.5 Mbbl/d capacity to the units.[76]

While several refineries are expanding now, and others will expand in the future, the construction of new refineries in the United States seems unlikely. According to several industry observers in one report, a new plant will not be built due to unattractive profit margins and environmental questions.[77] Before the Senate Subcommittee on Clean Air, Wetlands, Private Property and Nuclear Safety, the general counsel of the National Petrochemical and Refiners Association (NPRA) stressed the point that "rates of return for refineries have averaged about 5 percent in the last decade, roughly equivalent to the return from a passbook savings account – but with much greater risk." From this type of information, industry observers have concluded that new plants in new sites are highly unlikely to be built. Any future added capacity most likely would come from the expansion of existing refineries, because the construction of new refineries at new sites, and the necessary attraction of local support services, facilities, and skilled manpower, remain unattractive to the industry.

[75] *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

[76] *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

[77] "Refining Report: Future US Regulations, Product Demand." Oil & Gas Journal., March 19, 2001.

APPENDIX A

National Energy Policy Recommendations Related To NSR

Recommendation for a 90-day study of NSR

The NEPD Group recommends that the President to direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

Related NEP Recommendations

The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

• Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
• Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OCT 15 2012

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

MEMORANDUM

SUBJECT: Timely Processing of Prevention of Significant Deterioration (PSD) Permits when EPA or a PSD-Delegated Air Agency Issues the Permit

FROM: Stephen D. Page, Director Stephen Page
Office of Air Quality Planning and Standards

TO: Regional Air Division Directors, Regions 1-10

The purpose of this memo is to clarify expectations and responsibilities regarding the processing of Prevention of Significant Deterioration (PSD) permit applications when an EPA Regional Office (Regional Office) or a PSD-delegated air agency issues the PSD permit.

This memo summarizes the permit processing requirements of the Clean Air Act (CAA) and the EPA's implementing regulations, and identifies best practices and other recommended tools to foster timely and consistent permit processing across the Regional Offices under the applicable procedures in 40 CFR Part 124. Some other air agencies issue PSD permits under delegation of federal authority from the EPA [40 CFR 52.21(u)] and the EPA expects delegated air agencies to also follow this guidance. The timely processing goals and procedures in this memo should be applied to new PSD applications and to those applications already under review to the extent practicable. Air agencies that administer EPA-approved PSD permitting programs under their implementation plans should process their PSD applications in accordance with the procedures applicable under their EPA-approved implementation plan, but the EPA recommends these air agencies consider following the approaches outlined in this document to the extent that the applicable procedural requirements are comparable to those outlined in Part 124 of the EPA's regulations.

Timely processing of PSD permit applications is good public policy assuring permit applicants of timely action on their application and also ensuring that the Regional Office has adequate review time to make an informed permit decision. An efficient, yet well-informed, permit decision also ensures that the EPA's Environmental Appeals Board (EAB) has the time it needs to meaningfully review a permit decision on appeal. An EAB standing order calls for expedited handling of PSD permit appeals, in recognition of the time-sensitive nature of these permits.[1]

This document explains the requirements of the EPA regulations, describes the EPA policies, and recommends procedures for permitting authorities to use to ensure that permitting decisions are consistent with applicable regulations. This document is not a rule or regulation, and the guidance it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or other legally binding requirement and is not legally enforceable. The use of non-mandatory language such as "guidance", "recommend", "may", "should", and "can" is intended to describe the EPA's policies and recommendations. Mandatory terminology such as "must" and "required" are intended to describe controlling legal requirements under the terms of the CAA and the EPA regulations. Neither such language nor anything else in this document is intended to or does establish legally binding requirements in and of itself.

I. The Processing Goal - Permit Decision by the Regional Office within 10 Months

Under the CAA, the EPA is required to make a permit decision on a PSD permit application within 1 year after the application is complete as determined by the EPA. 42 U.S.C. 7475(c). The EPA's processing goal is that the Regional Office make a final permit decision (to issue or deny) on a PSD permit application within 10 months after the date that the Regional Office has determined that the application is complete. The EPA regulations define a complete application as one that "contains all of the information necessary for processing the application." 40 CFR 52.21(b)(22). The Regional Office makes the decision as to when the application is complete.

For some projects, the PSD permitting process is straightforward and noncontroversial, and the Regional Office can readily make a completeness determination and process the application expeditiously. This might occur, where, for example, the applicant submits a comprehensive and thorough application that the Regional Office determines early on to be complete, the Regional Office has no dispute regarding the applicant's analysis of Best Available Control Technology

[1] This requirement for timely processing of PSD permits was raised in the case of a PSD permit issued by the EPA for the Avenal Energy Project (Avenal). Avenal is a proposed combined-cycle gas-fired power plant near Avenal, California. The PSD permit application for this facility had been under review at the EPA for more than 3 years after the Agency had deemed the permit application complete. This led the applicant to seek and obtain a federal district court order based on CAA Section 165(c) imposing a deadline for final Agency action (to issue or deny a permit) within 90 days. *Avenal Power Center, LLC v. U.S. EPA*, 787 F. Supp.2d 1 (D.C. Dist. 2011). Although EPA disagreed with the decision, the Agency did not appeal and initially issued the permit the day after the judge's ruling. The permit was then appealed to the EAB, and EPA issued the final EPA permit within the 90 days as ordered. However, because of the short period for EAB review, the EAB lacked sufficient time to consider the most contentious issue (i.e., case-specific grandfathering from the 1-hour NO_2 NAAQS, SO2 NAAQS, and new GHG requirements that otherwise would have applied to the permit). EPA's action to issue the final permit has been challenged in federal court. This guidance is intended to reduce the likelihood of future lawsuits seeking a permit decision, and to put EPA in a position to respond quickly to any such lawsuits.

(BACT) or ambient impacts, and there is no reason for a public hearing. For such projects, comments are minimal and do not raise complex substantive issues and an appeal of the permit action is not anticipated, so it is unlikely that the EAB will be petitioned to review the permit before it becomes effective. For such projects Regions should be able to issue final permits within 10 months from the date that the Regional Office determines the application complete, although we recognize that there may be specific factors that lead the Regional Office to issue the final permit decision later than 10 months after the completeness determination.

Some other PSD projects are very complex, controversial, and contested. These projects typically require additional extensive and time-consuming technical review, multiple interactions with the applicant, scheduling and holding public hearings, and in some cases the development of further information in response to public comments. In such cases, it is very difficult to complete the permit application review process, including public involvement and response to comments, and make a permit decision within the 10-month goal. Regardless, for all PSD projects the Regional Offices should still make every effort to assure that their actions on permit applications are completed as expeditiously as possible, consistent with the need to ensure that the record supporting each permit action is sufficient to demonstrate that the application meets all applicable permitting requirements, and therefore is defensible if challenged.

If no comments were received that requested a change in the draft permit during the public comment period and all of the notice requirements of 40 CFR Section 124 are met, the final permit becomes effective immediately. If any such comments had requested a change to the draft permit but there is no appeal to the EAB, the permit decision becomes effective 30 days after issuance (or at a later time if the Regional Office has established a later effective date). 40 CFR 124.15(b). If such an appeal is requested, a PSD permit does not become effective until further proceedings are completed. 40 CFR 124.15(b)(2); 40 CFR 124.19. If the Regional Office can issue its decision on a PSD permit application within 10 months of the completeness determination and the permit action is appealed, then the administrative appeal process through EAB will likely be underway before an applicant (or an opponent of the permit) could file an action seeking an order directing EPA to take final action on the permit, which may reduce the incentive for such legal action. Appeals to the EAB historically have taken an average of 5 months from the time a petition is filed to the date of a final decision. The time for review and a final decision varies considerably depending on the volume and quality of the record, as well as the complexity of the issues.

II. Processing, Procedures, Practices, and Issues

The following discussion provides recommendations to facilitate timely processing of PSD permit applications. In addition, to promote consistency across all Regions, boilerplate language is suggested for Regional Offices to use when corresponding with a PSD permit applicant and other agencies, including acknowledgement of the application, notification to the Federal Land Manager(s) (FLM), request for additional information, complete and incomplete application notifications, denial, notice of constructive application withdrawal, and response to an applicant's request for the Regional Office to delay making a final permit decision. Of course, language should be tailored by the Regional Office to address the specific facts and context of the applicant and the permit application being reviewed. These and other issues are addressed in more detail below.

Acknowledgement, Application Tracking Database, Notification to FLM, Notification to Canada, Environmental Justice, and Tribal Consultation

Acknowledgement - Within 2 weeks of receipt, the Regional Office should acknowledge receipt of the PSD permit application by letter or email and include in this correspondence the contact information for the assigned Regional Office review staff. The acknowledgement should not attempt to address completeness, which the Region should address after further review.

Suggested Language

The EPA acknowledges receipt of your application for a permit under the Prevention of Significant Deterioration (PSD) requirements of 40 CFR 52.21. We expect to initiate review of your application as soon as possible and advise you within 30 days regarding our progress and if more information or more time is needed to enable the EPA to deem your application complete. Your review contact in the EPA Region [number] for this application is [name] at [phone] or [email].

Application Tracking Database –The Office of Air Quality Planning and Standards (OAQPS) has established a new PSD Permit Application Tracking database to track permit review from receipt of the permit application to the final agency action for PSD permit projects for which a Regional Office is the permitting authority. Regional Offices should also use the database to track PSD permit applications where the EPA's PSD permitting authority has been delegated to another air agency. The appropriate Regional Office should add (within 2 weeks of receipt) the proposed new or modified PSD project information into the tracking system as a new project and then update the information as the review progresses. All data entry fields that apply to the project should be completed. Using this database, the Regional Offices and OAQPS should periodically assess the progress of the review of these applications and resolve processing delays as needed.

Notification to FLM - Note that if the proposed project may affect a Class I area, within 2 weeks (and no later than 30 days) of receipt of the permit application the Regional Office should send a copy of the application and related materials to the FLM(s) and other federal official(s) directly responsible for any lands within such area(s). 40 CFR 52.21(p)(1). The Regional Office should determine the distance from the proposed source to the nearest Class I area(s). The EPA's policy is that the FLM(s) should be notified by the Regional Office about any project that is within 100 kilometers of a Class I area. For sources having the capability to affect air quality at greater distances, notification should also be considered for Class I areas beyond 100 kilometers. Applicants should be asked to submit an additional copy of the application for the Regional Office to submit to the FLM(s). The application should address the proposed source's anticipated impacts on the Class I area(s).

Suggested Language

In accordance with 40 CFR 52.21(p)(1), this letter is to notify you of the receipt of [company name]'s application dated [insert date] and received by this office on [insert date of receipt], for a Prevention of Significant Deterioration (PSD) permit for [project name]. The emissions from this project may affect a Class I area(s) for which you are the responsible federal official.

The application and supporting information are under review by this office for completeness. Due to proximity of the project to the [insert FLM area], we are asking for your input on the completeness of this application. Enclosed with this letter is a printed copy of the application [or compact disk, etc.] that contains all information submitted by [company name]. The application includes [or does not include] an analysis of the proposed source's anticipated impacts on visibility in the Class I area(s). Please provide any comments to us by [insert date].

If you have any questions concerning the review of the application, please contact [name] at [phone] or [email].

Notification to Canada - Under the 1991 Canada-U.S. Air Quality Agreement, Article V, each country agreed to notify the other regarding any planned new or modified industrial source of emissions that is located within 100 kilometers of the border. Regional Offices should provide information on the proposed PSD major new source or PSD modification to OAQPS. OAQPS will then notify Canada and post the information on the EPA's Technology Transfer Network at http://www.epa.gov/ttn/gei/uscadata.html.

Environmental Justice (EJ) - Executive Order (EO) 12898 provides for federal agencies to identify and address disproportionately high and adverse effects of their actions on minority, low-income, and tribal populations. The EPA defines EJ to include the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income in environmental decisions that affect them. Consistent with the Agency's commitment to environmental justice, as part of the permit review process and before issuing a PSD permit, the Regional Office should examine any superficially plausible claim that the facility seeking the PSD permit will disproportionately affect a minority, low-income, or tribal community. The EPA's policy, guidance, and information resources regarding EJ are at http://www.epa.gov/environmentaljustice/index.html. EJ guidance as reflected in EAB decisions may be found at the EAB website (www.epa.gov/eab).

Tribal Consultation – Under EO 13175 if the proposed project may affect tribal interests, the Regional Office should initiate consultation with the affected tribe(s) sufficiently early in the process to allow for meaningful input by the tribe(s). In accordance with the Regional Office's consultation plans and practices, the Regional Office should engage in such consultation prior to taking actions or implementing decisions that may affect the tribes. See the Tribal Consultation Policy dated May 4, 2011 at http://www.epa.gov/tp/pdf/cons-and-coord-with-indian-tribes-policy.pdf

A. Completeness Determination

A determination of application completeness by the EPA is a very important step because this starts the statutory 1-year decision clock for the EPA to either issue or deny the requested permit. The date of completeness is the date that the Regional Office notifies the applicant that the application is complete. 40 CFR 124.3(f). Once an application is determined to be complete, requests for additional information do not make the application incomplete. 40 CFR 124.3(c). Regional Offices should thus take the time needed to thoroughly review the application and not make a premature decision that an application is complete. The EPA rules define a "complete" application as one that "contains all the information necessary for processing the application." 40 CFR 52.21(b)(22). To avoid any misunderstanding regarding whether the 1-year decision clock has started, the term "administratively complete" should not be used, and the focus should be on whether the application contains all the information needed for the EPA to propose a permit decision. As a tool to assist in making this completeness determination, a listing and discussion of information needed in a PSD application are included in Appendix A.

The Goal - The goal is for the Regional Office to be proactive by notifying the applicant as soon as possible of application deficiencies (*e.g.*, lack of an adequate BACT analysis) to help decrease overall review and processing time. Experience shows that in some cases the receipt of requested information from the applicant and the subsequent review by the Regional Office may take several months or more. In some cases, there are long delays by the applicants in responding to information requested by the Regional Office. It is important that the applicant be notified in writing once the Regional Office has determined the application is complete (*i.e.*, the applicant has submitted all the information needed for the Regional Office to propose a decision regarding whether to issue or deny the permit). In some cases, it may not be possible to determine that the application is complete until shortly before or at the same time that the Regional Office proposes the permit action.

First 30 Days after Receipt - In keeping with the terms of 40 CFR 124.3(c) and the EPA's goals, the Regional Office should strive to review the application and determine whether the application is complete within 30 days of receipt. Below is suggested language for a situation where the application is complete as submitted. In cases where it is determined that the application is not complete, language similar to that in Section C below should be used.

Suggested Language

The EPA has reviewed your Prevention of Significant Deterioration (PSD) permit application for [name and location of project] that was received by the EPA on [insert date], including supporting documentation, and determined that as of [insert date of this letter] your application is complete. Even though your application is deemed complete, in the course of this review we may identify further information that will be essential to enable the EPA to continue processing your application and make a permit decision, including information that may be needed to respond to public comments.

If you have any questions please contact [name] at [phone] or [email].

B. Requests for Additional Information

When an application is not yet deemed complete - Regional Office requests for additional or clarifying information should be in writing and specify the information needed and an expectation of a response time (*e.g.*, 30, 60 days, etc.) for receiving the specific information from the applicant depending on the scope and complexity of the request. Any requests for information should affirm that the application is not yet complete.

Suggested Language

The EPA has reviewed your Prevention of Significant Deterioration (PSD) permit application for [name and location of project] that was received by the EPA on [insert date], including supporting documentation, and determined that your application is incomplete at this time. The following information is needed from you so that the EPA can continue its completeness review.

[List additional info needed, being as specific as possible. Propose a date for the applicant to provide the information.]

Please notify [name] if a complete response is not possible by this date. Your application is considered incomplete until this information is received and evaluated and the EPA has determined that the application contains all the information needed for the EPA to propose a permit decision. Note that as the EPA continues review of your application we may identify further information that will be essential to enable the EPA to continue processing your application and make a permit decision, including information that may be needed in response to public comments. If you have any questions please contact [name] at [phone] or [email].

When an application is already deemed complete - Experience shows that even after a careful completeness determination has been made by the Regional Office, the EPA may need to request more information from the applicant in order to complete review of the application and proceed to public notice of a proposed decision. Also, additional information may be needed from the applicant to respond to issues raised during public comment. For applications already deemed complete, if additional information is essential and needed from the applicant, the application remains complete and the 1-year permit decision clock is not stopped by the request. 40 CFR 124.3(c). However, the Regional Office's request for additional information will inform the applicant that the EPA will not be in a position to take permit action until the information is received and reviewed, even if that means delaying the decision beyond the 1-year decision time frame.

Suggested Language

The EPA has reviewed your Prevention of Significant Deterioration (PSD) permit application for [name and location of project] that was received by the EPA on [insert date], including supporting documentation, and determined complete by the EPA on [insert date]. Upon further review, the EPA has now determined that the following clarifying information from you is essential to enable the EPA to process your application and make a permit decision.

[List additional info needed, being as specific as possible. Propose a date for the applicant to provide the information.]

Please notify [name] if a complete response is not possible by this date.

This request does not affect the completeness of your application and the EPA will continue to review your application to the extent possible until the above information is received.

If you have any questions please contact [name] at [phone] or [email].

C. Project Changes by the Applicant

Sometimes, even after the Regional Office has deemed a permit application complete, the applicant may need to propose changes to the project or may discover and wish to correct substantial errors in its application. In some cases the submittal of changes will not impact the Regional Office's prior completeness decision and the running of the EPA's 1-year permit decision clock. However, if the applicant submits substantial changes to the project (*e.g.,* the addition of new emissions units or processes) or has identified substantial errors in the permit application (*e.g.,* the modeling is resubmitted to correct emissions rate calculations and erroneous stack exhaust parameters), the Regional Office may consider the revised or corrected PSD application to supersede (rather than supplement) the earlier application, such that it may be treated as newly submitted and not yet deemed complete. This means that the 1-year permit decision clock has not yet started on the new or revised project and will not start until the new information submitted by the applicant to support the proposed changes is deemed complete by the Regional Office. Even with a new 1-year decision clock, Regions should still strive to complete review as soon as possible, consistent with ensuring an appropriate, defensible permit decision.

Suggested Language

The EPA has reviewed your request to amend and supplement the Prevention of Significant Deterioration (PSD) permit application for [name and location of project] that was received by the EPA on [insert date], including supporting documentation, and previously determined complete on [insert date]. Because the changes to the project [or corrections to the application] are substantial, including [address specific changes or corrections here such as addition of new emissions units, changes in scope and purpose of project], the EPA has concluded that the *revised application for the project supersedes the earlier application. Thus, the EPA will treat the amended application as new and not complete. Even though we consider this submission to be equivalent to a new application for the project, we will strive to complete review as soon as possible.*

If you have any questions please contact [name] at [phone] or [email].

D. Requests by Applicants to Delay the EPA Permitting Decision

Permit applicants have sometimes requested that a permitting authority suspend its review of a permit application without withdrawing it. The Regional Office may put on hold the review of the permit application and consider it inactive, but should not do so unless the Regional Office obtains a written request from the permit applicant. If the application was previously determined complete by the EPA, the EPA considers the 1-year review clock stopped for such inactive applications. If the applicant wants the EPA to reactivate review, the applicant should contact the Regional Office to discuss reactivation and any additional or new information that may be needed from the applicant. Note that if and when the project is reactivated, it will need to meet the requirements applicable at the time the permit is issued.

Suggested Language

The EPA has reviewed your request dated [insert date] that the EPA cease processing the Prevention of Significant Deterioration (PSD) permit application for [name and location of project] that was received by the EPA on [insert date] and that we determined to be complete on [insert date], and put the permit decision on hold. Based on your request, effective [insert date], the EPA is placing your permit application on hold and considers it inactive. Please advise us if you would like to discuss reactivating your application and any additional information that may be needed. Note that if and when the project is reactivated, it will need to meet the requirements applicable at the time the permit is issued.

If you have any questions please contact [name] at [phone] or [email].

E. Preventing Inaction on Permit Processing

Absent a written request by a permit applicant to suspend review of an application, the Regional Office should proceed toward a decision on a permit application without delay. If the Regional Office is unable to propose or complete final approval of an application because an applicant stops responding, or is repeatedly nonresponsive to requests from the Regional Office for additional information, or the information provided does not demonstrate that the project meets the PSD requirements, the Regional Office has several options. Because of the statutory deadline, it is not advisable in these situations for a Regional Office to take no action on an application while the clock continues to run. If after a reasonable effort has been made by the Regional Office to obtain information that would support granting a permit the applicant has not adequately demonstrated compliance with all the PSD requirements, the EPA's options to avoid inaction include the following: 1) encourage the applicant to withdraw the application; 2) treat the application as constructively withdrawn; 3) repeat the information request with a clarifying explanation of the remaining deficiencies in the application; or 4) begin steps to deny the permit application.

Constructive withdrawal - If the applicant is known or suspected to have lost interest or has stopped responding to inquiries from the EPA, the Regional Office may consider the application to be withdrawn. For example, the applicant has not responded to several EPA requests for additional information and has not contacted the EPA to discuss reasons for the delay. Under the constructive withdrawal option, the Regional Office would notify the applicant that the permit application will be deemed withdrawn unless the applicant contacts the Regional Office within 30 days to discuss the status of the application and a plan to provide the requested information. If no response is received, the Regional Office will send a notice to the applicant that the permit application is considered withdrawn. If a response with the requested information is received and the information does not demonstrate compliance with the PSD requirements, the Regional Office may renew the information request with a clarifying explanation of the remaining deficiencies in the application or may use the denial option.

Suggested Language

This letter is in reference to your application for a Prevention of Significant Deterioration (PSD) permit for [name and location of project] that was received by the EPA on [insert date] and to our request(s) for additional information dated [insert date(s)]. It has been over [insert number of days, months or years as appropriate] since our last request and we still have not received a response that addresses our request. Accordingly, the EPA will consider your application as withdrawn unless you contact us within 30 days to discuss the status of your application and a plan to provide the information requested.

If you have any questions please contact [name] at [phone] or [email].

Permit denial – The denial of a PSD permit is not an approach that the EPA has traditionally taken. However, proceeding to denial may be an appropriate option where, for example, the applicant has not adequately modeled compliance with a NAAQS or where its proposed BACT analysis is unacceptable, and time is running out to be able to meet the 10-month goal for a final permit decision by the Regional Office. Denial may also be appropriate where the applicant refuses to provide information that the Regional Office believes is needed to make a defensible permit decision. In accordance with the administrative process at 40 CFR 124.6, 124.10, and 124.15 the Regional Office will propose and take public comment on a denial, giving the applicant the opportunity to respond before the Regional Office makes a final decision. A Regional Office denial of a permit is reviewable by the EAB.

Suggested Language

This letter is in reference to your application for a Prevention of Significant Deterioration (PSD) permit for [name and location of project] that was received by the EPA on [insert date] and to our request(s) for additional information dated [insert date(s)]. It has been over [insert number of days, months or years as appropriate] since our last request and {[we still have not received the requested information] or [the information you submitted in response to that request does not provide an adequate basis for issuing the requested permit]}. Based on this lack of needed information, the EPA believes it cannot lawfully grant the permit and is initiating the steps to deny your application. [Describe the next step(s).] The administrative process for denial of a PSD permit application is at 40 CFR 124.6, 124.10, and 124.15.

If you have any questions please contact [name] at [phone] or [email].

F. Requirements of Other Acts

In addition to the CAA requirements there are requirements in four other statutes that sometimes must be met before a source can begin construction and operation under a PSD permit. This justifies treating as requirements for completeness certain of the information needed from the applicant in order for the EPA to start, or complete, the appropriate review processes under these four statutes. As discussed further below, the other statutory requirements that may apply to the project are the Endangered Species Act (ESA), the Coastal Zone Management Act (CZMA), the National Historic Preservation Act (NHPA), and the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA).

The permit applicant should first initiate contact with the Regional Office and then with other implementing federal departments or agencies, state agencies, and tribal officials for these statutes to determine appropriate contacts and specific requirements that may apply to the proposed project. The applicant's contacts with the EPA and other federal, state, or tribal officials should be documented in the application along with the applicant's assessment of the applicability of these statutory requirements. In addition, the specific information needed from the applicant that is identified below for the four statutes, and any additional information that may be requested by the EPA, should be provided in the application. If the applicant does not address the applicability of these four statutes in the initial application, or does not provide the information identified below, this should be communicated to the applicant as a completeness gap in the application.

- **Endangered Species Act**

Under Section 7(a)(2) of the ESA, 16 U.S.C. § 1536(a)(2), the EPA must ensure that any action authorized, funded, or carried out by the EPA is not likely to jeopardize the continued existence of any federally listed endangered species or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. If the EPA's action (*i.e.,* permit issuance) may affect a federally listed species or designated critical habitat, Section 7(a)(2) of the

ESA and relevant implementing regulations at 50 CFR Part 402 require consultation between the EPA and the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service (NMFS), depending on the species at issue.

Under the ESA, applicants have certain opportunities to be involved in the Section 7(a)(2) compliance process. Under the ESA regulations, the EPA may also designate a non-federal representative to participate in, and conduct, certain aspects of a required consultation. 50 CFR 402.08. The Regional Office should work with the applicant to designate it as the non-federal representative. After first contacting the Regional Office to discuss the process, applicants should contact the FWS (and/or NMFS, if applicable) to ask whether there are any species or critical habitats listed or designated, or proposed for listing or designation, in the action area. The applicant should use this information to prepare a biological evaluation analyzing the impacts, if any, of the project on relevant species and critical habitat and provide a copy with the PSD application to assist the EPA in carrying out its responsibilities under ESA. The preparation of relevant analyses and fulfillment of ESA requirements is often a reason the issuance of a PSD permit is delayed; therefore, Regional Offices should strongly encourage applicants to work with the Regional Office, FWS, and the NMFS prior to submitting a PSD permit application.

- **Coastal Zone Management Act**

The CZMA encourages states to preserve, protect, develop, and where possible, restore or enhance valuable natural coastal resources such as wetlands, floodplains, estuaries, beaches, dunes, barrier islands, and coral reefs, as well as the fish and wildlife using those habitats. It includes areas bordering the Atlantic, Pacific, and Arctic Oceans, the Gulf of Mexico, Long Island Sound, and the Great Lakes. In any application for a PSD permit for a facility located in a state's coastal zone (or outside the state's coastal zone but affecting any land or water use or natural resource of the coastal zone), the applicant should provide the Regional Office with the applicant's own certification that the proposed activity complies with the enforceable policies of the state's NOAA-approved coastal program and that such activities will be conducted in a manner consistent with that program. The applicant also furnishes the state coastal zone management agency a copy of the certification, with necessary data and information. The state agency may concur or object to the consistency determination. The Regional Office cannot issue the license or permit until the state agency concurs in the certification or, through the state's failure to act, its concurrence can be conclusively presumed.

Accordingly, information as to whether the proposed facility is within the state's coastal zone or affects any land or water use or natural resource of the coastal zone is an application completeness item. Also, an application is not complete until it includes a copy of the applicant's certification of compliance and evidence that this certification has been furnished to the state coastal zone management agency. It is the Regional Office's responsibility to confirm the applicant has received concurrence (or presumed concurrence) from the state coastal zone management agency prior to the Regional Office taking final action to issue the permit.

- **National Historic Preservation Act**

Section 106 of the NHPA requires the EPA – prior to the approval of the expenditure of any funds on, or prior to the issuance of any license for, an undertaking – to take into account the effects of its undertakings on historic properties and afford the Advisory Council on Historic Preservation (the Council) a reasonable opportunity to comment with regard to such undertakings. 16 U.S.C. § 470f. Under the Council's implementing regulations at 36 CFR Part 800, section 106, consultation is required for all undertakings that have the potential to affect historic properties. Section 106 consultations assess whether historic properties exist within an undertaking's area of potential effect and, if so, whether the undertaking will adversely affect such properties. Consultation is generally with relevant state and tribal historic preservation authorities in the first instance, with opportunities for direct Council involvement in certain circumstances. Other interested entities may also be involved in the process, which must also provide for appropriate public involvement. Permit applicants are entitled to participate as a consulting party in the process and may be authorized by the EPA to initiate the consultation. The Regional Office should discuss this possible authorization upfront with the permit applicant prior to initiating consultation. As part of the permit application, the applicant should furnish its assessment of whether historic properties exist within the source's area of potential effect. If so and there are adverse effects to such properties caused by the project, the application should also discuss ways to avoid, minimize, or mitigate such effects. The term "historic properties" means prehistoric or historic districts, sites, buildings, structures, or objects included in, or eligible for inclusion in, the National Register of Historic Places maintained by the Department of the Interior. Historic properties include properties of traditional religious and cultural importance to an Indian Tribe or Native Hawaiian organization.

- **Magnuson-Stevens Fishery Conservation and Management Act**

The MSFCMA was enacted to promote the U.S. fishing industry's optimal exploitation of coastal fisheries by consolidating control over territorial waters to manage fish stocks. Implementation of the MSFCMA is by the U.S. Department of Commerce, National Marine Fisheries Service (NMFS), and its appointed regional fishery management councils. As part of the permit review process, the Regional Office should discuss the project with the applicant and the NMFS and the applicant may include as part of the permit application an assessment that, if determined adequate to meet the EPA's obligations under the MSFCMA and implementing regulations, the EPA would transmit to the NMFS for its review as appropriate.

G. New Regulatory Requirements

New EPA regulations (*e.g.*, new or revised NAAQS, requirements to control new pollutants) may become effective and incorporated into the applicable PSD permitting requirements after the date that the EPA determined the application complete. These requirements apply to any final permit issued after the effective dates of the requirements unless the EPA has provided for grandfathering of the specific requirements for applications pending on the effective date of the new requirement. If new requirements apply to an application under review, the Regional Office should as promptly as possible inform the applicant in writing, request the needed information with respect to the new requirements, state that the information is necessary for processing the application, communicate that the application is incomplete, and explain that the EPA will not be able to complete its review until the requested information is received. The EPA does not interpret the last sentence of section 124.3(c) (see Appendix B) to be applicable when new requirements apply to a pending permit application. Any prior determination that an application was complete would have been based on requirements applicable at that time. When permitting requirements change, an application that does not adequately address the new requirements will become incomplete by operation of law and the request for additional information will be necessary to ensure that the new requirement is addressed in the application. Even though the application has become incomplete because of a new requirement, the Region is encouraged to continue review of the application based on the information submitted to date.

H. Using Electronic Docketing for Comments

One approach that can help Regional Offices decrease permit processing time is to direct commenters on a proposed permit action to provide their comments directly to the federal government's electronic docketing system at http://www.regulations.gov/, or to a contact person at the Regional Office who then submits them to the electronic docket. If the docketing system is used directly, then comments do not need to be submitted in paper form. Use of *Regulations.gov* is required for all the EPA rulemaking actions, but is available and is used by some Regional Offices for permitting actions as well. For Regional Offices, using the electronic docket system can lighten the task of dealing with high volumes of form letters and other comments. It also provides more transparency, by allowing commenters near real-time access to each others' comments. Properly managed, it also avoids delays in being able to provide parties who are appealing permit decisions to the EAB with a copy of the administrative record of the action. Questions and answers regarding the Federal Docket Management System are at https://fdms.erulemaking.net/fdms-web-agency/component/loginInfo?page=faq

III. Final Action and Review by EAB

A. Final Steps to Completing Permit Decisions

After the comment period on a permit closes, the next step is for the Regional Office to make any needed changes to the draft permit in light of public comments, prepare responses to public comments, compile the appropriate record, and issue a final permit decision. 40 CFR 124.15; 40 CFR 124.17; 40 CFR 124.18. Issuance of the final permit decision includes providing notice of that decision to the applicant and each person who commented or requested notice. 40 CFR 124.15(a). A final permit decision cannot be issued before the full record is completed (including the response to comments document).[2] If many comments are received and the comments raise

[2] *In Re Prairie State Generation Station*, 12 E.A.D. 176 (EAB 2005) (remanding final permit decision issued before completing response to comments document).

complex issues, this step can be time consuming and some comments may require new information for an adequate response. Permit review time can be reduced by focusing effort on these tasks as soon as the comment period closes or even as soon as the expected major comments have been received, but Regional Offices should ensure the record supporting the final permit decision is complete. The Agency's highest priority is to make appropriate permit decisions, based on records that fully support those decisions. A Regional Office should not compromise the quality of the record supporting the final permit decision in pursuit of quicker action. Doing so may result in a decision that is more vulnerable to a remand upon review by the EAB for the reasons discussed in the next section or to being overturned in any subsequent judicial appeal.

If the Regional Office received no comments that requested a change in the draft permit during the public comment period and if the notice requirements of 40 CFR Section 124 are met, the final permit becomes effective immediately. 40 CFR 124.15(b)(3). If the Regional Office received comments that requested a change to the draft permit but there is no appeal to the EAB, the permit decision becomes effective 30 days after issuance (or at a later time if the Regional Office has established a later effective date). 40 CFR 124.15. To ensure timely action, it is recommended that the Regional Office avoid extending the effective date of a PSD permit beyond the minimum 30-day period that applies in most cases. Within this 30-day period, interested parties may file a petition requesting review of the PSD permit decision by the EAB. If such an appeal is requested, a PSD permit does not become effective until further proceedings are completed. 40 CFR 124.15(b)(2); 40 CFR 124.19.

B. EAB Review

EAB review historically has taken an average of 5 months from the time a petition is filed to the time the EAB issues its decision in the matter. The EAB has issued a standing order to assist the EAB in expediting further its PSD appeal process *(available at www.epa.gov/eab).*

Although the EAB is cognizant that permitting decisions should be made at the Regional Office level and will typically defer to the Regional Office on technical issues that are well supported in the administrative record, the EAB will take a close look at the record to determine whether the Regional Office has duly considered the issues raised in comments. If the EAB finds that a permit condition is based on a clearly erroneous or insufficiently explained finding of fact or conclusion of law by the Regional Office, the EAB may grant review and remand the permit to the Regional Office to correct the error. Correcting such errors can take several months, especially where additional public comment is solicited on the portions of the permit or supporting rationale that need to be corrected. Many of the EAB's past remands were due to an inadequate record. Thus, being careful to ensure the final permit decision is well supported can avoid delays in completing action on a PSD permit.

Record deficiencies usually cannot be cured on appeal to the EAB, necessitating a remand. When an appeal to the EAB reveals record deficiencies, permit issuers are encouraged to withdraw a permit under the process described in section 124.19 or seek a voluntary remand depending on the status of the appeal. Curing the record promptly prior to an EAB decision can shorten the time it takes to issue a final defensible Agency action.

Regional Offices can take several steps that have the potential to reduce the time it takes the EAB to resolve a petition for review of a permit and reduce the chance of a remand. One such step is to ensure that the permitting record is complete and is indexed and certified promptly. Each Regional Office should also make sure its reasoning is clearly articulated and well supported in the Statement of Basis, Response to Comments, and any supplemental documents as needed. The timing and efficiency of EAB review may also be improved by precisely pinpointing where in the record the Regional Office's rationale and support for that rationale can be found.

C. Final Agency Action Letter

If review by the EAB is requested, the permit does not become final and effective until after agency review procedures under 40 CFR Part 124 are exhausted and the Regional Administrator subsequently issues a final permit decision. Under 40 CFR 124.19, agency review procedures are exhausted either when the EAB issues a decision on the merits of the appeal and the decision does not include a remand of the proceedings; or upon the completion of remand proceedings if the proceedings are remanded, unless the EAB's remand order specifically provides that appeal of the remand decision will be required to exhaust administrative remedies.

EPA Offices have not always consistently interpreted this provision. The Office of Air and Radiation recently observed that one final action had occurred on the date the EAB issued a decision denying review. *See,* Letter from Assistant Administrator for Air and Radiation to Jim Rexroad, Avenal Power Center, LLC (August 26, 2011); 76 FR 55799 (Sept. 9, 2011). However, based on recent litigation under the National Pollutant Discharge Elimination System program and Underground Injection Control program, the EPA believes the better reading of section 124.19 is that final agency action for purposes of judicial review does not occur on matters appealed to the EAB until the Regional Administrator takes the additional step, after review procedures are exhausted, of issuing a final permit decision under section 124.19. The EPA's interests and those of the public are best served by conforming the Agency's interpretation of section 124.19 across all program areas to which this provision is applicable.

Therefore, to complete final agency action on a permit decision expeditiously, Regional Offices should issue a letter formatted as follows[3] as soon as agency review procedures are exhausted as provided in section 124.19.

[3] Regional Offices should not follow the format of the letter issued by OAR on August 26, 2011 for the Avenal permit. This is recommended to facilitate a consistent reading of section 124.19 on a prospective basis across all programs that apply this regulation, and is not intended to suggest any error in prior actions. Any prior PSD permitting decisions that were determined by EPA to be final and effective on the date of an EAB order meeting the

Suggested Language

[address of permit applicant]

Re: [permit applicant name and number]

Dear [applicant]:

The United States Environmental Protection Agency, Region [number] is hereby issuing and providing you with notice of its final permit decision on [permit number], which the EPA Region [number] initially issued to [applicant] for the [description of project] on [date] under 40 CFR 124.15.

On [date], the EPA's Environmental Appeals Board denied review of all petitions for review of the permits. [cite order denying review.] Thus, in accordance with 40 CFR 124.19, this letter serves as the final permit decision by EPA Region [number] for the permit. All conditions of [permit number], as issued by Region [number] on [date], are final and effective as of the date of this letter.

Public notice of this final agency action will be published in the Federal Register pursuant to 40 CFR 124.19.

Sincerely,

[name]

Regional Administrator

As discussed in the template above, with respect to PSD permits, section 124.19 of the EPA's regulations states that "[n]otice of any final agency action regarding a PSD permit shall promptly be published in the Federal Register." Regional Offices should publish such a notice promptly to initiate the 60 day period for requesting judicial review and to comply with section 124.19, but such notice is not the action that renders the permit decision final and effective.

---

criteria in section 124.19 continue to be final and effective as of the date identified by EPA. The August 26, 2011, letter from the Assistant Administrator for Air and Radiation to Avenal Power Center, LLC was sufficient to serve as a final permit decision under the interpretation of section 124.19 recommended for PSD permitting actions from this point forward. Therefore, under either the interpretation applied in that action or the interpretation recommended in this memorandum, EPA issued a final decision granting the Avenal permit application by the deadline established by court order. Avenal Power Center, LLC v. U.S. EPA, F. Supp.2d 1.

For any questions on this guidance or appendices, please contact Raj Rao at (919) 541-5344 or rao.raj@epa.gov.

cc: Mike Koerber
Anna Wood
Richard Wayland
Phil Lorang
Raj Rao
Brian Doster

APPENDICES

APPENDIX A - Comprehensive PSD Permit Applications– What Information Is Needed?

Introduction and Overview

The submittal of comprehensive Prevention of Significant Deterioration (PSD) permit applications that address all the PSD requirements is a first step towards timely processing of permit applications by the Regional Offices. The EPA should strongly encourage applicants to engage the Regional Office early-on in the application development process and to contact Regional Office review staff for pre-application discussions and meetings as needed, especially regarding modeling air impacts, meeting pre-construction monitoring requirements, using the "top-down" methodology for evaluating Best Available Control Technology (BACT), and contacting other federal agencies, and state, local, or tribal governments or agencies that may be involved. Applicants should be strongly encouraged to submit a written modeling protocol to the Regional Office for review prior to conducting modeling and to discuss the possible and appropriate use of existing ambient air monitoring data. The information below is intended to assist both applicants in preparing applications and the EPA in determining if information and analyses addressing all required components of the application have been submitted. As part of the review process, the EPA will request from the applicant any missing components and any needed clarifying or additional information. Only when the applicant has submitted all information needed for the EPA to propose a permit decision should the Regional Office deem the application to be complete. *A determination of completeness by the EPA is very important because this initiates the 1-year statutory period for the EPA to make a decision to issue or deny the requested permit.*

Applications

Each proposed new or modified PSD project has unique source characteristics, such as site location, process configuration, topography, and ambient impacts. However, there are some common PSD requirements and related issues that each application should address. For example, applications should include a detailed description of the project, location, processes, emissions units, and associated air pollutant emissions. Applications should address PSD applicability for each regulated New Source Review (NSR) air pollutant, emissions controls, and ambient impacts. Applications should demonstrate that all PSD program requirements are met for each regulated NSR pollutant that will be emitted in major amounts or cause a major modification. As discussed below in more detail, PSD permit applications submitted to the Regional Office for review and permit action should address all PSD requirements and include:

1. A Project Overview and Description,
2. A PSD Applicability Section,
3. A "Top-down" BACT analysis for each regulated NSR pollutant subject to major PSD review,

4. An Air Quality Analysis for the National Ambient Air Quality Standards (NAAQS) and PSD increments, as applicable for each regulated NSR pollutant subject to major PSD review,
5. An Analysis of Class I Areas Impacts,
6. An Analysis of the New Source or Project's Impacts on Visibility, Soils, Vegetation, and the Impact on Associated Growth for the Project or New Source,
7. Compliance with other EPA Air Regulations [such as New Source Performance Standards (NSPS)],
8. Compliance with Non-Clean Air Act (CAA) Requirements such as the Endangered Species Act (ESA), and
9. Clear Identification of Confidential Business Information Claims, if needed.

1. Project Overview and Description

A. ***Applicant Information*** - The application should list the name, mailing address (street, city, state, zip code), email address, and telephone number of the applicant, the owner/operator (if different from the applicant), any consultants, and the designated contact for the project. The application must be signed by a responsible official. 40 CFR 124.3(a).

B. ***Project Location*** - Describe the project location by address (street, city, state) and map location (UTM or Lat/Long coordinates), and the current use of the project site. Provide local and regional maps showing the location of the project. Discuss location of the source in relation to Class I areas.

Note that if the proposed project may affect a Class I area, within 30 days of receipt of the permit application the Regional Office should send a copy of the application to Federal Land Manager(s) (FLM) and other Federal official(s) directly responsible for any lands within such area.

C. ***Project Description*** - Provide the purpose of the project and include the Standard Industrial Classification (SIC) code(s). Provide a detailed description of all processes, process equipment, storage units, raw materials used, fuels to be burned, emission control systems, all emission sampling ports and continuous monitoring systems, and any other information necessary to completely describe the proposed project and its air pollutant emission points. Include a schematic drawing and plot plan of the project showing the design and plant layout that identifies each air pollution emission point, property and fence line, buildings, etc.

For each proposed or modified emission unit, provide its design capacity, date of emission unit construction or modification, anticipated operating capacity (*i.e.,* projected average and maximum) and operational schedule including daily or seasonal variations. For each emission control system, provide the make and model of the device, the control efficiency of the system, and required operating parameters. Describe any work practices used to prevent or reduce air emissions.

D. ***Construction Schedule*** – Provide a detailed construction schedule for the proposed source or modification.

2. PSD Applicability Section

The application should address the applicability of PSD to the project (a proposed new major stationary source or a proposed modification) for all regulated NSR pollutants based on the proposed emissions of each pollutant in tons per year. The applicant should address whether the source is major for PSD purposes at 100 tons per year (tpy) or 250 tpy, based on its SIC codes. The applicant should list the attainment status of the area for each criteria pollutant. The applicant should also identify and address the applicability of and plans to comply with any other EPA air requirements such as applicable NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP).

The application should contain the following information:

- All emissions of regulated NSR pollutants, including emissions calculations. A permit application shall describe all emissions of regulated NSR pollutants emitted from each emissions unit, except units that are exempt.
- Identification and description of all points of emissions release.
- Emissions rate in tpy, short term rates (*e.g.,* pounds/hour) for use in air quality impact assessments, and in any other such terms as are necessary to establish compliance consistent with the applicable standard reference test method. Include methods used to derive the emission rates, including information sources used such as manufacturer's warranties, stack test results, etc.
- Operational restrictions (existing or proposed) that limit equipment's "potential to emit". (Sometimes an existing permit limits the potential emissions of a particular emission unit or units; these should be identified and included in the permit application.)

3. A "top-down" Best Available Control Technology (BACT) analysis for each regulated NSR pollutant subject to major PSD review

The EPA's policy is that the "top-down" BACT process, developed by the EPA, is the best way to make the demonstration that an applicant satisfies the BACT requirements. Thus, to demonstrate that the BACT requirement is satisfied, on a per pollutant basis, the application should include a "top-down" BACT analysis for each emission unit that emits regulated NSR pollutants for which the source is subject to major PSD review. The analysis should be consistent with the EPA's "top-down" BACT guidance. This guidance is included in the draft 1990 NSR Workshop Manual as well as more recent discussions of the elements needed to successfully apply the "top-down" BACT process reflected in EAB decisions, orders on title V permits, and other relevant EPA guidance documents. http://www.epa.gov/NSR/publications.html. EAB decisions in PSD permit appeals may be found at the EAB website (www.epa.gov/eab), under Board Decisions, Published, PSD Permit Appeals. EPA has also recently provided guidance on the top-down BACT process in section III of its PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) (http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf).

4. Air Quality Analysis for the National Ambient Air Quality Standards (NAAQS) and PSD Increments, as applicable for each regulated NSR pollutant subject to major PSD review

The EPA's regulations require the permit applicant to submit for review an air quality analysis for each regulated NSR pollutant that will be emitted in significant amounts "in the area that the major stationary source or major modification would affect." 40 CFR 52.21(m). This pollutant-specific analysis typically entails a modeling component and an ambient air quality monitoring component. The information provided in meeting this requirement must demonstrate that the emissions from the new source or modification will not cause or contribute to a violation of any NAAQS or PSD increment. 40 CFR 52.21(k)(1).

Modeling Analysis – Estimates of ambient concentrations required to meet the PSD requirements must be based on applicable models, data bases, and other requirements specified in the Guideline on Air Quality Models (Guideline). 40 CFR 52.21(l); 40 CFR Part 51, Appendix W. To ensure that any air quality analysis meets the applicable regulatory requirements and is consistent with the Guideline, the EPA strongly recommends that the applicant submit a modeling protocol to the Regional Office prior to performing the air quality analyses. It is both advantageous and advisable that the applicant prepare a modeling protocol to ensure that planned modeling analyses meet the needs of other federal agencies (*e.g.*, FLM). The EPA recommends that applicants consult with the Regional Office to determine the nature of ambient air quality monitoring data that is needed (40 CFR 52.21(m)(3)(iii)-(viii)) and/or the need (if any) for site-specific meteorological monitoring.

Air Quality Data – The required air quality analysis should also consider the existing ambient air quality at the proposed site for those regulated NSR pollutants emitted from the project in significant amounts. The air quality data used for the analysis may be obtained from monitoring carried out by the applicant; however, in many cases the analysis may be based on data from existing monitoring sites that provide data representative of the area affected by the proposed project's emissions. The record for the required analysis should include such items as the source of the data and the number and location of monitoring stations. The applicant should also include a brief description of the local meteorological conditions that would affect transport and dispersion of pollutants, describe the source of meteorological data to be used, the range of dates of the data, and the representativeness of the data for application at the proposed plant site. It is also recommended that the proposed air quality data and meteorological data be included in the modeling protocol submitted to the Regional Office. Recommendations concerning ambient air quality and meteorological data collection in support of PSD applications are presented in the EPA publications EPA-450/4-80-012, Ambient Monitoring Guidelines for Prevention of Significant Deterioration, and EPA-454/R-99-005, Meteorological Monitoring Guidance for Regulatory Modeling Applications.

A description of any monitoring program that the applicant intends to initiate should be submitted to the EPA for approval prior to commencing the program.

5. Analysis of Class I area impacts

The applicant is required to provide an air quality analysis for any Class I area that may be affected by the emissions from the proposed new source or modification. There are two components for this analysis — the NAAQS and Class I increments analysis, and the air quality related values (AQRV) analysis. Such analysis is preceded by a notification process in which the appropriate FLM for the Class I area(s) potentially affected by the proposed new source or modification is advised by the Regional Office of the PSD application and given an opportunity to determine the extent of the analysis needed for any air quality related values that have been identified for the Class I area. It is important to recognize that the compliance determination for the NAAQS and Class I increments is the responsibility of the Regional Office, while the FLM has an affirmative responsibility for protecting the AQRVs in the Class I area and may demonstrate that a proposed source or modification would have an adverse impact on AQRVs.

The Regional Office should determine the distance from the proposed source to the nearest Class I area(s). The EPA's policy is that the FLM should be notified by the Regional Office about any project that is within 100 kilometers of a Class I area. For sources having the capability to affect air quality at greater distances, notification should also be considered for Class I areas beyond 100 kilometers. In such cases, the appropriate FLM should be contacted by the Regional Office to determine if an analysis of the impacts on the AQRV in the Class I area is needed. The applicant should contact the Regional Office to determine the need for and appropriate assessment procedures to address the NAAQS and Class I increments. If an AQRV impact analysis is needed, a copy of the PSD application should be provided to the FLM by the Regional Office. The project's modeling protocol should include PSD Class I assessments and be provided to the appropriate FLMs and to the Regional Office for review, discussion, and approval.

6. Analysis of impacts on visibility, soils, vegetation, and associated growth for the proposed project or new source

Additional Impact Analysis **-** As required by 40 CFR 52.21(o) of the PSD regulations, the applicant must provide an analysis of the proposed facility's impact on soils, vegetation and visibility and the expected general commercial, residential, and industrial growth associated with the new or modified source.

If no impacts are anticipated, then the analysis can generally be qualitative in nature and designed to provide the basis for this determination and inform the general public of the relative impact of the project/source on the above cited values. The proposed analyses to address these items should be included in the modeling protocol provided to the EPA.

7. Compliance with other emissions standards or standards of performance (such as NSPS)

List and describe all other emissions standards and standards of performance applicable to the proposed project (*e.g.,* NSPS, NESHAPS, State Implementation Plan and Federal Implementation Plan requirements, local district rules). Summarize the status of all other air pollution permits required, applied for and/or received for the proposed project or new source.

8. Non-Clean Air Act requirements such as the ESA

See Section II.G of this memo.

9. Confidential Business Information claims (see instructions below)

An applicant may assert a business confidentiality claim covering part or all of the information requested by the EPA by placing on (or attaching to) the information, at the time it is submitted to the EPA, a cover sheet, stamped or typed legend, or other suitable form of notice employing language such as "trade secret," "proprietary," or "company confidential." Allegedly confidential portions of otherwise non-confidential documents should be clearly identified by the business, and should be submitted separately to facilitate identification and handling by the EPA. If the applicant desires confidential treatment until a certain date or until the occurrence of a certain event, the notice should clarify this request. Information covered by such a claim will be disclosed by the EPA only to the extent and by means of the procedures set forth in 40 CFR Part 2, Subpart B. If no such claim accompanies the information when received by the EPA, it may be made available to the public by the EPA without further notice to the applicant. If a claim covering the information is received after the information itself is received, the EPA will make such efforts as are administratively practicable to associate the late claim with copies of previously submitted information files. However, the EPA cannot assure that such efforts will be effective, in light of the possibility of prior disclosure or widespread prior dissemination of the information.

INSTRUCTIONS FOR CLAIMING CONFIDENTIALITY

A. Pursuant to 40 CFR 2.204(e), your claim must address these points:

i. The portions of the information alleged to be entitled to confidential treatment;

ii. The period of time for which confidential treatment is desired by the business (e.g., until the occurrence of a specific event, or permanently);

iii. The purpose for which the information was furnished to the EPA and the appropriate date of submission, if known;

iv. Whether a business confidentiality claim accompanied the information when it was received by the EPA;

v. Measures taken by you to guard against the undesired disclosure of the information to others;

vi. The extent to which the information has been disclosed to others and the precautions taken in connection therewith;

vii. Pertinent confidentiality determinations, if any, by the EPA or other Federal agencies, and a copy of any such determination or reference to it, if available;

viii. Whether you assert that disclosure of this information would be likely to result in substantial harmful effects on your business' competitive position, and if so, what those harmful effects would be, why they should be viewed as substantial; and an explanation of the casual relationship between disclosure and such harmful effect; and

ix. Whether you assert that the information is voluntarily submitted information and if so, whether any disclosure of the information would tend to lessen the availability to the EPA of similar information in the future. "Voluntarily submitted information" is defined in 40 CFR Section 2.201(i) as business information in the EPA's possession.

a) The submission of which the EPA has no statutory or contractual authority to require; and

b) The submission of which was not prescribed by statute or regulation as a condition of obtaining some benefit (or avoiding some disadvantage) under a regulatory program of general applicability, including such regulatory programs as permit, licensing, registration, or certification programs, but excluding programs concerned solely or primarily with the award or administration by the EPA of contracts or grants.

B. We will disclose information covered by your claim only to the extent provided for in 40 CFR Part 2, Subpart B Confidentiality of Business Information.

APPENDIX B – Regulations for PSD Permit Processing

40 CFR 124.3(c)

(c) The Regional Administrator shall review for completeness every application for an EPA-issued permit. Each application for an EPA-issued permit submitted by … a major PSD stationary source or major PSD modification … should be reviewed for completeness by the Regional Administrator within 30 days of its receipt. … Upon completing the review, the Regional Administrator shall notify the applicant in writing whether the application is complete. If the application is incomplete, the Regional Administrator shall list the information necessary to make the application complete. … The Regional Administrator shall notify the applicant that the application is complete upon receiving this information. After the application is completed, the Regional Administrator may request additional information from an applicant but only when necessary to clarify, modify, or supplement previously submitted material. Requests for such additional information will not render an application incomplete.

40 CFR 124.3(f)

(f) The effective date of an application is the date on which the Regional Administrator notifies the applicant that the application is complete as provided in paragraph (c) of this section.

40 CFR 124.4(e)

(e) Except with the written consent of the permit applicant, the Regional Administrator shall not consolidate processing a PSD permit with any other permit under paragraph (a) or (b) of this section when to do so would delay issuance of the PSD permit more than one year from the effective date of the application under 40 CFR 124.3(f).

40 CFR 52.21(b)(22)

Complete means, in reference to an application for a permit, that the application contains all of the information necessary for processing the application.

APPENDIX C – Example of ESA Consultation Letter

Sent to U.S. Fish & Wildlife Service and/or NOAA's National Marine Fisheries Service

By this letter, the United States Environmental Protection Agency, [*insert Region*] requests informal consultation and concurrence under Section 7 of the federal Endangered Species Act (ESA) for the proposed [*insert project name)*]. The Prevention of Significant Deterioration (PSD) Application consists of [*insert project description*]. The proposed project will result in a [*insert summary of emission changes*]. The Project is located [*insert project location*].

In processing the PSD permit application, the EPA must assure that listed species or their critical habitat will not be jeopardized by the changes at the [*insert facility name*] facility. The information provided in the application is not detailed enough for us to determine our obligations, if any, under Section 7 of the ESA.

The EPA would like to begin an informal consultation with the [*insert appropriate service: U.S. Fish and Wildlife or National Marine Fisheries*] Service regarding the proposed project. [*insert applicant/company name*] has been designated by the EPA as the non-federal representative, and will be responsible for preparing and submitting a complete biological evaluation to the EPA and to the Service.

In summary, pursuant to Section 7 of the ESA, we request informal consultation and an evaluation in writing as to what impact, if any, the Project may have on relevant endangered species. We look forward to working with you on this matter. If you have any questions, please contact [*name*] at *[phone] or [email]*.

To: Johnson, Yvonne W[johnson.yvonnew@epa.gov]
From: Wood, Anna
Sent: Thur 3/23/2017 10:42:43 PM
Subject: Spring 2016 Update w_TPs_final draft.pptx
Spring 2016 Update w_TPs_final draft.pptx

To: 'vera kornylak'[kornylak.vera@epa.gov]
From: Wood, Anna
Sent: Mon 6/19/2017 6:48:28 PM
Subject: FW: Emailing - nsr_report_to_president.pdf
fact sheet 06-13-2002.pdf
nsr_recommendations 06-2002.pdf
nsr_report_to_president 06-2002.pdf
nsr-review 06-22-2001.pdf

Just an FYI for now—**Ex. 5 - Deliberative Process** **Ex. 5 - Deliberative Process**—I am taking a closer look at it and we can touch base on it on Thursday. Thx!

From: Keller, Peter
Sent: Monday, June 19, 2017 2:18 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: RE: Emailing - nsr_report_to_president.pdf

I thought I would go ahead and send the all the "90 day study" docs so you could file them away. The fact sheet is kind of handy in terms of tying things together.

Peter Keller

OAQPS/AQPD/NSRG

919-541-2065

From: Keller, Peter
Sent: Monday, June 19, 2017 2:01 PM
To: Wood, Anna <Wood.Anna@epa.gov>
Subject: Emailing - nsr_report_to_president.pdf

Let me know if this is not what you were looking for.

Peter

Fact Sheet - NEW SOURCE REVIEW (NSR) REPORT AND IMPROVEMENTS

[June 13, 2002] Acting on the broad-based, bipartisan call for improving the New Source Review (NSR) program, the U.S. Environmental Protection Agency (EPA) announced steps to increase energy efficiency and encourage emissions reductions. EPA today submitted a report on NSR and recommendations for reform to President Bush. As recommended by the 2001 National Energy Policy, EPA reviewed the potential impact of the NSR program on investment in new utility and refinery capacity, energy efficiency and environmental protection.

EPA's review found that the NSR program has impeded or resulted in the cancellation of projects that would maintain or improve reliability, efficiency or safety of existing power plants and refineries. Reforms to NSR will remove barriers to pollution prevention projects, energy efficiency improvements, and investments in new technologies and modernization of facilities.

For more than 10 years and through three administrations, EPA has worked closely with a large and diverse group of stakeholders to find ways to improve the NSR program. During this period, EPA implemented pilot studies and received thousands of comments from state and local governments, environmental groups, industry representatives and private citizens. Over the past year, EPA met with more than 100 environmental and consumer groups and public officials from across the political spectrum, held public meetings around the country, and evaluated more than 130,000 written comments to assess the effect of NSR on the energy sector. Just last summer, the nation's Governors and state environmental commissioners - on a bipartisan basis - both reiterated the call for reform of the NSR program. After a decade of discussion, it is time to act.

Therefore, in addition to the Report to the President, EPA is issuing a document summarizing improvements the Agency intends to make to the NSR program. EPA will be taking these actions to reduce the complexity of the NSR program, promote energy efficiency and pollution prevention, and enhance energy security while encouraging emissions reductions.

These improvements include moving forward to finalize NSR rule changes that were recommended in 1996 and proposing some new changes to the rules. The 1996 recommendations were subject to extraordinarily extensive technical review and public comment over the past six years. EPA will fully involve the public and other stakeholders before finalizing the new proposals.

The actions being taken today will not take away the strong public health protection provided by the Clean Air Act through the National Ambient Air Quality Standards and the programs that ensure their compliance. The key provisions of the Clean Air Act include other programs designed to protect human health and the environment from the harmful effects of air pollution and all those remain in place.

SUMMARY OF IMPROVEMENTS

When Congress established the New Source Review Program, it did so with a goal of providing for economic growth while maintaining or improving air quality. Today's announced reforms improve the program to ensure that it is meeting these goals. These reforms will:

- Provide greater certainty about which activities are covered by the NSR program;
- Remove barriers to environmentally beneficial projects;
- Provide incentives for industries to improve environmental performance at the same time they make changes to their facilities; and
- Maintain provisions of NSR and other Clean Air Act programs that protect air quality.

EPA has spent 10 years looking for ways to improve the NSR program. As a follow-up to that work and the previous Administration's proposals to reform NSR, EPA recommends finalizing the following NSR reforms, all of which were originally proposed in 1996:

- **Pollution Control and Prevention Projects:** To encourage pollution control and prevention, EPA will create a simplified process for companies that undertake environmentally beneficial projects. NSR currently discourages investments in certain pollution control and prevention projects, even if they reduce overall emissions.
- **Plantwide Applicability Limits (PALs):** To provide facilities with greater flexibility to modernize their operations without increasing air pollution, a facility would agree to operate within strict sitenwide emissions caps called PALs. PALs provide clarity, certainty and superior environmental protection.
- **Clean Unit Provision:** To encourage the installation of statenofnthenart air pollution controls, EPA will give plants that install "clean units" operational flexibility if they continue to operate within permitted limits. Clean units must have an NSR permit or other regulatory limit that requires the use of the best air pollution control technologies.
- **Calculating Emissions Increases and Establishing Actual Emissions Baseline:** Currently, the NSR program estimates emissions increases based upon what a plant would emit if operated 24 hours a day, year-round. This makes it impossible to make certain modest changes in a facility without triggering NSR, even if those changes will not actually increase emissions. This common-sense reform will require EPA to evaluate how much a facility will actually emit after the proposed change. Also, to more accurately measure actual emissions, account for variations in business cycles, and clarify what may be a "more

representative" period, facilities will be allowed to use any consecutive 24-month period in the previous decade as a baseline, as long as all current control requirements are taken into account.

EPA is also proposing three new reforms that will go through new rulemaking and public comment processes before they are finalized. These include:

- **Routine Maintenance, Repair and Replacement:** To increase environmental protection and promote the implementation of necessary repair and replacement projects, EPA will clarify the definition of "routine" repairs. NSR excludes repairs and maintenance activities that are "routine," but a complex analysis must currently be used to determine what repairs meet that standard. This has deterred companies from conducting needed repairs, resulting in unnecessary emissions of pollution and hazardous conditions at these plants. EPA is proposing guidelines for particular industries to clearly establish what activities meet this standard.
- **Debottlenecking:** EPA is proposing a rule to clarify how NSR applies when a company modifies one part of a facility in such a way that throughput in other parts of the facility increases (i.e., implements a "debottlenecking" project). Under the current rules, determining whether NSR applies to such complex projects is difficult and can be time consuming.
- **Aggregation:** Currently, when multiple projects are implemented in a short period of time, a difficult and complex analysis must be performed to determine if the projects should be treated separately or together (i.e., "aggregated") under NSR. EPA's proposal will establish two criteria that will guide this determination.

BACKGROUND

Congress established the New Source Review program as part of the 1977 Clean Air Act Amendments and slightly modified it in the 1990 Amendments. NSR was designed to help clean up air in areas with air quality problems, and protect air quality in areas where it is good.

Over time, the NSR program has become continually more complex and complicated, due to the evolving nature of industrial practices and changes in the regulations and EPA's interpretation of them. In response to concerns about this, EPA has worked for nearly 10 years to simplify the NSR program.

In 1992, EPA issued a regulation addressing issues regarding NSR at electric utility steam generating units making major modifications. This is referred to as the "WEPCO" rule.

In 1996, EPA proposed to make changes to the existing NSR program that would significantly streamline and simplify the program.

Following the 1996 proposals, EPA held two public hearings and more than 50 stakeholder meetings. Environmental groups, industry, and state, local and federal agency representatives participated in these many discussions. Despite widespread acknowledgment of the need for reforms, EPA did not finalize these proposed regulations in 1996.

In May 2001, the National Energy Policy Development Group issued its National Energy Policy Report. This document included numerous recommendations for action, including a recommendation that the EPA Administrator, in consultation with the Secretary of Energy and other relevant agencies, review New Source Review regulations, including administrative interpretation and implementation. The recommendation requested EPA to issue a report to the President on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

In June 2001, EPA issued a background paper giving an overview of the NSR program. EPA solicited public comments on the background paper and other information relevant to New Source Review. EPA met with more than 100 environmental and consumer groups and public officials, held public meetings around the country, and
evaluated more than 130,000 written comments EPA evaluated those comments in formulating its report to the President.

EPA's in-depth study of the NSR program has shown that it has an adverse impact on investment in expanding and preserving capacity, as well as in energy efficiency. It found that investment is hindered by (1) regulatory uncertainty and lack of flexibility resulting from the program's complexity, and (2) the added costs and delays imposed by the NSR process – the NSR permit process can add a year or more to the time needed to review proposed plant modifications, and cost over $1 million. As a result, many companies delay or abandon plans to modernize their facilities in ways that would benefit the environment. These reforms will facilitate improvements in these facilities that will be good for the environment, such as energy efficiency and pollution prevention projects, while retaining the elements of NSR that protect our air quality.